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

FORM 10-K

☑ **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: 1-33266

DUNCAN ENERGY PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**20-5639997**
(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 o No ☑

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

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

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 o	Accelerated filer ☑
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 ☑

The aggregate market value of Duncan Energy Partners L.P.'s ("DEP's") common units held by non-affiliates at June 30, 2010, was approximately $620.5 million, 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 Dan Duncan LLC and Enterprise Products Operating LLC. There were 57,749,158 common units of DEP outstanding at February 1, 2011.

DUNCAN ENERGY PARTNERS L.P.
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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to “we,” “us,” “our,” or “Duncan Energy Partners” are intended to mean the business and operations of Duncan Energy Partners L.P. and its consolidated subsidiaries. References to “DEP GP” mean DEP Holdings, LLC, which is our general partner. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. References to “DEP OLP” mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners. Duncan Energy Partners conducts substantially all of its business through DEP OLP and its consolidated subsidiaries.

References to “Enterprise” mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise 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 “EPD.” 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 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”). References to “EPO” mean Enterprise Products Operating LLC, whic h is a wholly owned subsidiary of Enterprise and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. EPO beneficially owns 100% of DEP GP and currently owns 58.5% of our common units. Enterprise consolidates our financial statements with its own. See “Significant Recent Developments” within Item 1 of this annual report for information regarding Enterprise’s February 22, 2011 offer to acquire all of our outstanding publicly-held common units.

On September 3, 2010, Enterprise GP Holdings L.P. (“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.

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 Enterprise GP, 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.

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, Enterprise, EPO, DEP GP, 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 an d 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 a s the independent co-executors of the estate of Mr. Duncan.

References to the "DEP I Midstream Businesses" collectively refer to: (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene"), including its general partner; and (v) South Texas NGL Pipelines, LLC

(“South Texas NGL”). We acquired controlling ownership interests in the DEP I Midstream Businesses from EPO effective February 1, 2007 in a drop down transaction (the “DEP I drop down”) in connection with our initial public offering.

References to the “DEP II Midstream Businesses” collectively refer to: (i) Enterprise GC, L.P. (“Enterprise GC”); (ii) Enterprise Intrastate L.P. (“Enterprise Intrastate”); and (iii) Enterprise Texas Pipeline LLC (“Enterprise Texas”). We acquired controlling ownership interests in the DEP II Midstream Businesses from EPO on December 8, 2008 in a drop down transaction (the “DEP II drop down”).

References to “Evangeline” mean our aggregate 49.51% equity method investment in Evangeline Gas Pipeline Company, L.P. (“EGP”) and Evangeline Gas Corp (“EGC”).

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 subsidiaries of Enterprise on October 26, 2009.

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.” 0;Enterprise owns noncontrolling interests in Energy Transfer Equity, which it accounts 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,” “may,” “potential” and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking state ments. 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.

PART I

Item 1 and 2. *Business and Properties.*

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." We were formed in September 2006 and did not own any assets prior to February 5, 2007, which was the date we completed our initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. Our business purpose is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. We are engaged in the business of: (i) natural gas liquids, or NGLs, transportation, fractionation and marketing; (ii) storage of NGL, petrochemical and refined products; (iii) transportation of pe trochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas. We conduct substantially all of our business through DEP OLP. 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.deplp.com.

At December 31, 2010, we were owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP. EPO beneficially owned approximately 58.5% of our common units and 100% of DEP GP at December 31, 2010. DEP GP is responsible for managing our business and operations. EPCO provides all of our employees and certain administrative services to us.

See "Significant Recent Developments" within this Item 1 for information regarding Enterprise's February 22, 2011 offer to acquire all of our outstanding publicly-held common units.

Our relationship with EPO is one of our principal business advantages. Our assets connect to various midstream energy assets of EPO and form integral links within EPO's value chain of assets. We believe that the operational significance of our assets to EPO, as well as the alignment of our respective economic interests in these assets, will result in a collaborative effort between us and EPO to promote the operational efficiency of our assets and maximize their value. See Item 13 of this annual report and Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our extensive and ongoing relationships with EPCO and EPO.

The following information summarizes the businesses acquired and consideration we provided in connection with the DEP I and DEP II drop down transactions.

DEP I Drop Down

Effective February 1, 2007, EPO contributed to us a 66% controlling equity interest in each of the DEP I Midstream Businesses in a drop down transaction. EPO retained the remaining 34% noncontrolling equity interest in each of these businesses.

The following is a brief description of the assets and operations of the DEP I Midstream Businesses:

- Mont Belvieu Caverns owns 34 underground salt dome storage caverns located in Mont Belvieu, Texas, having an NGL and related product storage capacity of approximately 100 million barrels ("MMBbls"), and a brine system with approximately 20 MMBbls of above ground storage capacity and related brine production wells.

- Acadian Gas is engaged in the gathering, transportation, storage and marketing of natural gas in south Louisiana, utilizing over 1,000 miles of pipelines having an aggregate throughput capacity of approximately 1.1 billion cubic feet per day ("Bcf/d"). Acadian Gas also owns a 49.51% equity interest in Evangeline, which owns a 27-mile natural gas pipeline located in southeast Louisiana.

- § Lou-Tex Propylene owns a 267-mile pipeline used to transport chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas.

- § Sabine Propylene owns a 21-mile pipeline used to transport polymer-grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana.

- § South Texas NGL owns a 297-mile pipeline system used to transport NGLs from our Shoup and Armstrong NGL fractionation facilities in South Texas to Mont Belvieu, Texas.

DEP II Drop Down

On December 8, 2008, EPO contributed to us the following controlling equity interests in a second drop down transaction: (i) a 66% voting general partner interest in Enterprise GC, (ii) a 51% voting general partner interest in Enterprise Intrastate and (iii) a 51% voting membership interest in Enterprise Texas. As consideration for these equity interests, we paid $280.5 million in cash and issued 37,333,887 Class B units to EPO (which automatically converted on a one-for-one basis to common units in February 2009). The cash portion of this consideration was financed with $280.0 million in borrowings under our Term Loan Agreement and $0.5 million of net cash proceeds from an equity offe ring to EPO. The market value of the Class B units at the time of issuance was approximately $449.5 million. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the Term Loan Agreement.

The following is a brief description of the assets and operations of the DEP II Midstream Businesses:

- § Enterprise GC operates and owns: (i) two NGL fractionation facilities, the Shoup and Armstrong facilities, located in South Texas; (ii) a 1,185-mile NGL pipeline system located in South Texas; and (iii) 1,096 miles of natural gas gathering pipelines located in South and West Texas. Enterprise GC’s natural gas gathering pipelines include: (i) the 262-mile Big Thicket Gathering System located in southeast Texas; (ii) the 660-mile Waha system located in the Permian Basin of West Texas; and (iii) the 174-mile TPC Offshore gathering system located in South Texas.

- § Enterprise Intrastate operates and owns an undivided 50% interest in the assets comprising the 641-mile Channel natural gas pipeline, which extends from the Agua Dulce Hub in South Texas to Sabine, Texas located on the Texas/Louisiana border.

- § Enterprise Texas owns the 6,653-mile Enterprise Texas natural gas pipeline system, which includes the Sherman Extension and Trinity River Lateral pipelines, and leases the Wilson natural gas storage facility. The Enterprise Texas pipeline system and the Wilson storage facility, along with the Waha, TPC Offshore and Channel pipeline systems, comprise our Texas Intrastate System.

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (the “Tier I distribution,” based on our $730.0 million aggregate investment) and then to EPO (the “Tier II distribution”), in amounts sufficient to generate an annualized return to both owners based on their respective investments. Distributions in excess of these amounts (the “Tier III distributions”) will be allocated 98% to EPO and 2% to us.

The initial annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, which was based on our estimated weighted-average cost of capital at December 8, 2008 plus 1.0%. The annualized return rate increases by 2.0% on January 1 of each year. As a result, the annualized return rate for 2010 was 12.087% and for 2011 will be 12.329%.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity’s percentage interest of 22.6% and 77.4%, respectively, and then in a manner that in part follows the cash distributions paid by (or contributions made to) each DEP II Midstream Business. The

22.6% and 77.4% amounts represent each owner's initial relative economic investment in the DEP II Midstream Businesses at December 8, 2008.

For detailed information regarding EPO's noncontrolling interest in the DEP I and DEP II Midstream Businesses, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Business Strategy

Our primary business objectives are to maintain and, over time, to increase our cash available for distribution to unitholders. Our business strategies to achieve these objectives are to:

- optimize the benefits of our economies of scale, strategic location and pipeline connections serving natural gas, NGL, petrochemical and refining customers;
- manage our portfolio of midstream energy assets to minimize volatility in our cash flows;
- invest in organic growth capital projects to capitalize on market opportunities that expand our asset base and generate additional cash flow; and
- pursue acquisitions of assets and businesses from related parties or, in accordance with our business opportunity agreements, from third parties.

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. For information regarding our capital spending program, see "Liquidity and Capital Resources – Capital Expenditures," included under Item 7 of this annual report.

Significant Recent Developments

Enterprise Offers to Acquire Publicly-Held Common Units of 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 our 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 of our outstanding publicly-held common units as part of a transaction that would be structured as a merger between us 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 our common units and the closing price of Enterprise common units on Fe bruary 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 Facility

On February 8, 2011, a fire occurred at our Mont Belvieu, Texas underground 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 cau se of the event. The Mont Belvieu underground storage facility is owned by Mont Belvieu Caverns, which is owned 66% by Duncan Energy Partners and 34% by EPO. 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.

DEP Multi-Year Revolving Credit Facility and $400 Million Term Loan Facility

In October 2010, we entered into new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion (collectively, the "Revolving Credit and Term Loan Agreement"). The new 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 "$400 Million Term Loan Facility"). At closing in October 2010, we borrowed the full amount available under the $400 Million Term Loan Facility to repay principal amounts outstanding under our then existing $300 million unsecured revolving credit facility (the "Revolving Credit Facility") and the $200 million revolving loan agreement with EPO (the "Loan Agreement with EPO"). Upon repayment of the principal amounts outstanding, both the Revolving Credit Facility and the Loan Agreement with EPO were terminated. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding the Revolving Credit and Term Loan Agreement.

We entered into these new credit facilities primarily to fund our capital spending requirements under the Haynesville Extension project. See "Segment Discussion – Natural Gas Pipelines & Services" included under this Item 1 and 2 discussion for additional information regarding our Haynesville Extension project. Variable interest rates charged under the Revolving Credit and Term Loan Agreement are based on the London InterBank Offered Rate (or "LIBOR") or a base rate, both as defined in the Revolving Credit and Term Loan Agreement.

For additional information regarding this and 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

See Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for 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.

Segment Discussion

We have three reportable business segments:

§ Natural Gas Pipelines & Services;

§ NGL Pipelines & Services; and

§ Petrochemical Services.

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.

A related party, EPO, is our largest customer and accounted for 34.6% and 33.8% of our consolidated revenues during 2010 and 2009, respectively. Evangeline, another related party, was our largest customer during 2008 and accounted for 22.7% of our consolidated revenues. See Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our related party revenues from EPO and Evangeline. Our largest non-affiliated customer is Exxon Mobil Corporation and its affiliates (collectively, "Exxon Mobil"), which accounted for 7.4%, 7.5% and 10.0% of our consolidated revenues in 2010, 2009 and 2008, respectively.

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

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

For information regarding our results of operations, including significant measures of historical throughput and fractionation 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.

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.

Natural Gas Pipelines & Services

Our Natural Gas Pipelines & Services business segment includes approximately 9,400 miles of natural gas pipeline systems that provide for the gathering and transportation of natural gas in Louisiana and Texas. We lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our related natural gas marketing activities.

Natural gas pipelines and related marketing activities. Our natural gas pipeline systems provide for the gathering and transportation of natural gas from major producing regions such as the Barnett Shale, Permian and Eagle Ford supply basins and from offshore developments in the Gulf of Mexico through connections with offshore pipelines. We also have an ongoing expansion project on our Acadian Gas System to provide services to producers in the Haynesville Shale supply basin in northwest Louisiana. Our natural gas pipelines receive n atural 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 pipelines.

Our 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 Texas Railroad Commission. Certain of our 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. The results ofoperations for our natural gas pipelines are generally dependent upon the volume of natural gas transported and/or firm capacity reserved and the level of fees we charge for such services. The results of operations from our natural gas marke ting activities are generally dependent on sales volumes and prices.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes in connection with our natural gas marketing activities. For example, on certain segments of our Texas Intrastate System, we purchase natural gas from certain producers and resell the natural gas to third parties. In addition, Acadian Gas enters into a limited number of offsetting derivatives that effectively fix the price of natural gas for certain of its customers. We use derivative instruments to mitigate our exposure to commodity price risks associated with our natural gas pipelines and services business.&# 160; For more information regarding our use of derivative instruments, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Underground natural gas storage. We lease underground salt dome natural gas storage caverns that are integral components of our Texas Intrastate and Acadian Gas Systems. These 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 desi re 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 allow customers to take advantage of periods of volatile natural gas prices and respond quickly in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities.

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

Seasonality. Typically, our 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 storag e facilities.

Competition. Within their market areas, our 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 f acilities. 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.

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

Description of Asset	Location	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Working Capacity (Bcf)
Natural gas pipelines:				
Texas Intrastate System	Texas	8,128	6,640	
Acadian Gas System	Louisiana	1,041	1,149	
Big Thicket Gathering System (1)	Texas	262	60	
Total miles		9,431		
Natural gas storage facilities:				
Wilson (2)	Texas			6.8
Acadian (3)	Louisiana			1.3
Total gross capacity				8.1

(1) The Big Thicket Gathering System is an integral part of our NGL marketing activities, the results of operations of which are accounted for under our NGL Pipelines & Services business segment.
(2) This facility is held under an operating lease that expires in January 2028.
(3) This facility is held under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our natural gas pipelines were approximately 58.8%, 62.5% and 68.3% 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. For recently constructed assets, our utilization rates reflect the periods since the dates such assets were placed into service.

The following information highlights the general use of each of our principal natural gas pipelines, all of which we operate except for small segments of the Texas Intrastate System.

§ 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. Our Texas Intrastate System is strategically located to benefit from increasing natural gas production from the Eagle Ford Shale basin located in South Texas.

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 by customers, including EPO, under long-term contracts.

In July 2010, we completed and placed into service the final segment of our Trinity River Lateral natural gas pipeline. In total, the Trinity River Lateral pipeline extends approximately 40 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 Bcf/d of production takeaway capacity.

Construction projects for the Texas Intrastate System in the Eagle Ford Shale supply basin include an expansion of its rich natural gas mainline that will add three additional pipeline segments totaling 168 miles. Upon completion in mid-2012, this 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 to be constructed and owned by EPO. 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 will terminate at our Wilson natural gas storage facility. We are also constru cting 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. EPO is funding all of the capital expenditures associated with these expansion capital projects. The aggregate estimated cost of these expansion projects is approximately $1.15 billion.

As a result of the DEP II drop down transaction, we own a 51% equity interest in the entities that own the Enterprise Texas and Channel pipeline systems and lease the Wilson storage facility. In addition, we own a 66% equity interest in the entity that owns the Waha and TPC Offshore gathering systems. EPO owns the remaining equity interests in these entities.

§ 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 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 EPO 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 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, we agreed to fund 66% of the Haynesville Extension project costs and EPO agreed to fund the remaining 34% of such expenditures; therefore, we estimate that our share of such costs will approximate $1.03 billion. In order to address our funding requirements under the Haynesville Extension project, we entered into new long-term senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010.

For information regarding our agreements with EPO related to the Haynesville Extension, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For information regarding our $1.25 billion credit facilities, see Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

As a result of the DEP I drop down transaction, we own a 66% equity interest in the entities that own the Acadian Gas System. Acadian Gas owns a 49.51% equity interest in Evangeline, which owns a 27-mile natural gas pipeline in southeast Louisiana.

Evangeline's most significant contract is a natural gas sales agreement with Entergy Louisiana ("Entergy") that expires in January 2013. Under this contract, Evangeline is obligated to make available-for-sale and deliver to Entergy certain specified minimum contract quantities of natural gas on an hourly, daily, monthly and annual basis. The sales contract provides for minimum annual quantities of 36.8 BBtus of natural gas.

In connection with the Entergy sales contract, Evangeline has entered into a natural gas purchase agreement with a subsidiary of Acadian Gas that contains annual purchase provisions. The pricing terms of Evangeline's sales contract with Entergy and its purchase agreement with a subsidiary of Acadian Gas are based on a monthly weighted-average market price of natural gas (subject to certain market index price ceilings and incentive margins) plus a predetermined margin. Our natural gas sales to Evangeline totaled $174.5 million, $155.5 million and $362.9 million for the years ended December 31, 2010, 2009 and 2008, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract was 36.8 BBtus for each of the years ended December 31, 2010 and 2009 and 36.9 BBtus for the year ended D ecember 31, 2008.

In 1991, Evangeline entered into an agreement with Entergy whereby Entergy was granted the right to acquire Evangeline's pipeline system for a nominal price, plus the assumption of all of Evangeline's obligations under the natural gas sales contract. The option period began on July 1, 2010 and terminates on December 31, 2012. While Entergy has expressed an interest in exercising this purchase option, we cannot ascertain when, or if, it will be exercised. This uncertainty results from various factors, including decisions by Entergy's management and regulatory approvals that may be required for Entergy to acquire Evangeline's assets.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our NGL and related product storage facility located in Mont Belvieu, Texas, our South Texas NGL System (pipelines and fractionators) and the results from NGL marketing activities related to our Big Thicket Gathering System. Our South Texas NGL System is a group of assets comprised of approximately 1,480 miles of NGL pipelines and two NGL fractionators in South Texas and includes the leased Markham and Almeda NGL storage facilities.

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 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.

NGL and related product storage facilities. Our NGL, petrochemical and refined products storage facilities receive, store and deliver NGL, petrochemicals and refined products for industrial customers located along the Texas Gulf Coast. This area has the largest concentration of petrochemical plants and refineries in the United States. Our NGL, petrochemical and refined products storage facilities are interconnected by multiple pipelines to other producing and offtake facilities throughout the Gulf Coast region, including EPO's NGL import and export facility located on the Houston Ship Channel, as well as connections to (i) the Rocky Mountain and Midwest regions via EPO's Seminole pipeline, (ii) Louisiana via EPO's Lou-Tex NGL pipeline and (iii) East Texas via EPO's Panola pipeline.

We also store certain petrochemicals such as propylene (chemical, polymer and refinery grades) and ethylene. Chemical-grade propylene is a petrochemical used in plastics, synthetic fibers and foams. Polymer-grade propylene is primarily used in the manufacture of polypropylene, which has a variety of end uses, including packaging film, carpet and upholstery fibers and plastic parts for appliances, automobiles and medical devices. Refinery grade propylene is produced by refineries and is used as a feedstock in the production of polymer-grade and chemical-grade propylene. Ethylene is also a key building block for the petrochemical industry. Ethylene derivatives are used in film applications for packagin g, carrier bags and trash liners. Other applications include injection molding, pipe extrusion and cable sheathing and insulation, as well as extrusion coating of paper and cardboard.

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). 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 customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we generally charge custo mers throughput fees based on volumes placed into and withdrawn from storage. Lastly, revenues are derived from the sale of brine to customers that use brine in the production of chlorine and caustic soda, which is used in the production of polyvinyl chloride ("PVC") and for industrial products used in crude oil production and fractionation. Brine is produced by placing fresh water into a well to create cavern space within the salt dome. This process creates brine for our customers and develops new underground wells for product storage. Accordingly, the profitability of our storage operations is dependent upon the level of storage capacity reserved by customers, the volume of product placed into and withdrawn from the underground caverns, the level of fees charged and the volume of brine produced and sold to customers.

We have a broad range of customers for our storage services with contract terms that vary from month-to-month to long-term contracts with durations of one to ten years. We currently offer our customers, in various quantities and at varying terms, two main types of storage contracts: multi-product fungible storage and segregated product storage. Multi-product fungible storage allows customers to store any combination of fungible products. Segregated product storage allows customers to store non-fungible products such as propylene, ethylene and naphtha. Segregated storage allows a customer to reserve an entire storage cavern and have its own product injected and withdraw n without having its product commingled. We evaluate pricing, volume and availability for storage on a case-by-case basis.

Storage well measurement gains and losses occur when underground storage wells are physically emptied. Storage well gains and losses are a result of volumetric measurement differences on aggregate volumes of product injected into a storage well and the aggregate volumes withdrawn from storage. In connection with storage agreements entered into between EPO and Mont Belvieu Caverns, effective concurrently with the closing of our initial public offering, EPO agreed to assume all storage well measurement gains and losses.

Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances. The Mont Belvieu Caverns' limited liability company agreement allocates to EPO any items of income or loss relating to net operational measurement gains and losses, including amounts that Mont Belvieu Caverns may retain as handling losses. As such, EPO is required each period to contribute cash to Mont Belvieu Caverns for net operational measurement losses and is entitled to receive distributions from Mont Belvieu Caverns for net operational measurement gains. We continue to record operational measurement g ains and losses associated with our Mont Belvieu storage complex as a component of operating costs and expenses. However, these operational measurement gains and losses do not affect our net income attributable to Duncan Energy Partners L.P. or have a significant impact on us with respect to the timing of our net cash flows provided by operating activities and, accordingly, we have not established a reserve for operational measurement losses on our balance sheet. We recognized a net operational measurement gain of $9.5 million for the year ended December 31, 2010. We recognized net operational measurement losses of $1.7 million and $6.8 million for the years ended December 31, 2009 and 2008, respectively. All items of income and loss relating to these net operational measurement gains and losses have been appropriately allocated to EPO.

NGL pipelines and related marketing activities. Our NGL pipelines (i) transport mixed NGLs from natural gas processing facilities and refineries to NGL fractionation plants and storage facilities and (ii) distribute and collect purity NGL products to and from NGL fractionation plants, petrochemical plants, refineries and our Mont Belvieu storage complex. Revenues from our NGL pipeline transportation agreements are generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. However, rev enues recorded by our subsidiary South Texas NGL from its NGL transportation agreement with EPO are based on a fixed fee per gallon of liquids multiplied by the total volume of NGLs processed at the Shoup and Armstrong NGL fractionators whether or not such NGL volumes are transported on the pipeline owned by South Texas NGL (such pipeline being a component of the South Texas NGL System). Accordingly, the results of operations for this business are generally dependent upon the volume of product transported or processed at Shoup and Armstrong, as applicable, and the level of fees charged to customers. The transportation fees charged under these arrangements are contractual and not typically regulated by governmental agencies. Typically, we do not take title to the products transported in our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

The NGL marketing activities associated with our Big Thicket Gathering System generate revenues from the sale and delivery of NGLs we take title to through natural gas processing agreements at EPO's Indian Springs natural gas processing plant located in East Texas. The results of operations from our NGL marketing activities are generally dependent upon the volume of products sold and the market-based sales prices charged to customers. EPO is the primary customer of our NGL marketing activities.

NGL fractionation. Our Shoup and Armstrong NGL fractionators process mixed NGLs supplied by EPO's South Texas natural gas processing plants. Revenues from our NGL fractionators are generally based on fee-based arrangements for our NGL fractionation services. Purity NGL products from the Shoup and Armstrong fractionators are generally transported to Mont Belvieu, Texas on the pipeline owned by South Texas NGL.

Based on industry data, we believe that there will be sufficient quantities of natural gas in South Texas to support the production of mixed NGLs for more than twenty years. For example, exploration and production activity has increased in the emerging Eagle Ford Shale supply basin, which is believed to cover more than 10 million acres in southern Texas. Certain natural gas production from this region is rich in NGLs, which must be removed before the natural gas can meet quality specifications to be acceptable for transportation in the nation's natural gas pipeline systems or for commercial use as a fuel.

Seasonality. Our NGL fractionation and pipeline operations typically exhibit little to no seasonal variation. 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. Our facilities located along the Gulf Coast may also be affected by weathe r events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Our competitors in the NGL and related product storage business are integrated major oil companies, chemical companies and other storage and pipeline companies. With respect to our Mont Belvieu underground storage complex, we primarily compete against LDH Energy Mont Belvieu L.P., Targa Resources, Inc. and ONEOK Partners, L.P. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability. We believe that fees we charge our storage customers are competitive with those charged by othe r storage operators because we have historically been able to renew existing contracts as they mature, resulting in many long-standing customer relationships. We also believe that the number of pipelines connected to our storage facilities allows us to offer customers a wider variety of receipt and delivery options with respect to key Gulf Coast petrochemical plants, NGL fractionators and other users of the products we store.

Furthermore, we believe that our emphasis on maintenance and safety provides our customers with a high level of confidence in our operational dependability.

Our South Texas NGL System is not affected by competition given that EPO is the primary customer of these businesses.

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

Description of Asset	Location	Length (Miles)	Usable Storage Capacity (MMBbls)	Total Plant Capacity (MBPD)
NGL pipelines:				
South Texas NGL System - Pipelines	Texas	1,482		
NGL, petrochemical and refined products storage facilities:				
Mont Belvieu Storage (34 caverns) (1)	Texas		100.0	
Almeda (5 caverns) (1, 2)	Texas		13.0	
Markham (2 caverns) (1, 2)	Texas		4.3	
Total usable capacity			117.3	
NGL fractionation facilities:				
South Texas NGL System - Shoup fractionator	Texas			77
South Texas NGL System - Armstrong fractionator	Texas			20
Total plant capacities				97

(1) The Mont Belvieu storage complex includes above-ground brine pit capacity of 20 MMBbls. Brine capacity at the Almeda and Markham facilities is limited to the quantity necessary to support the product storage operations.
(2) Our interest in these facilities is held under long-term operating leases.

The maximum number of barrels that our NGL pipelines in South Texas can transport per day depends upon the operating balance achieved at a given point in time between various segments of this system. Since the operating balance is dependent upon the mix of products being shipped and demand levels at various delivery points, the exact capacities of such pipelines cannot be reliably determined. We measure the utilization rate of our NGL pipelines in South Texas in terms of average throughput. Total average throughput volume for this pipeline was 123 MBPD, 109 MBPD and 126 MBPD during the years ended December 31, 2010, 2009 and 2008, respectively.

On a weighted-average basis, aggregate utilization rates for our NGL fractionation plants were approximately 83.6%, 86.8% and 84.3% during the years ended December 31, 2010, 2009 and 2008, respectively.

The following information highlights the general use of each of our principal NGL pipeline, storage and fractionation assets, all of which we operate except for the leased Markham NGL storage facility.

§ The *Mont Belvieu Storage* complex consists of three interconnected underground storage facilities: East Storage, West Storage and North Storage. The East Storage facility is the largest of our three Mont Belvieu storage facilities. This facility consists of 14 underground salt dome storage caverns with a storage capacity of approximately 56 MMBbls and an above-ground brine pit with a brine capacity of approximately 10 MMBbls. This facility also has two brine production wells. 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. See "Significant Recent Develo pments" within this Item 1 and 2 for information regarding a fire that occurred at the West Storage facility in February 2011. The North Storage facility consists of 10 underground salt dome storage caverns with a storage capacity of approximately 30 MMBbls and an above-ground brine pit with a brine capacity of approximately 8 MMBbls.

During 2010, we elected to participate with EPO 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.

Our storage customers include a broad range of NGL, petrochemical and refined products producers and consumers, including many of the largest petrochemical facilities and refineries in the Texas and Louisiana Gulf Coast region. Our three largest third-party storage customers, which accounted for a combined 18.2% of our segment revenues for the year ended December 31, 2010, were Exxon Mobil, Lyondell Basell and Koch Industries, Inc.

We also provide underground storage services to EPO, which accounted for 31.7% of our Mont Belvieu storage revenues for the year ended December 31, 2010.

As a result of the DEP I drop down transaction, we own a 66% equity interest Mont Belvieu Caverns. EPO owns the remaining equity interests in this entity.

§ The *South Texas NGL System* consists of our South Texas NGL pipelines and fractionators and includes the leased Markham and Almeda NGL storage facilities.

In South Texas, we have (i) intrastate NGL transportation pipelines that transport mixed NGLs from various South Texas natural gas processing facilities (primarily those owned by EPO) to our Shoup and Armstrong fractionators, (ii) intrastate NGL pipelines that deliver NGLs 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 and (iii) an intrastate NGL pipeline that delivers NGLs from the Shoup and Armstrong fractionators to our Mont Belvieu storage complex. The leased Markham and Almeda NGL storage facilities are integral components of our NGL pipelines in South Texas.

The Shoup NGL fractionator is located in Corpus Christi, Texas and receives mixed NGLs from six natural gas processing plants located in South Texas. The Armstrong NGL fractionator is located in DeWitt County, Texas and fractionates mixed NGLs for EPO's Armstrong natural gas processing plant.

In May 2010, we and EPO 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 Shale supply basin. In June 2010, we completed modifications to our Shoup facility, which increased its NGL fractionation capacity to 77 MBPD. In January 2011, we completed modifications to infrastructure at the Armstrong facility, which increased its NGL fractionation capacity to 20 MBPD. The $24 million aggregate cost of these expansion projects was funded entirely by EPO.

EPO is the primary customer of our South Texas NGL System and accounted for 83% of revenues generated by these assets for the year ended December 31, 2010.

As a result of the DEP I and DEP II drop down transactions, we own a 66% equity interest in the entities that own the South Texas NGL System. EPO owns the remaining equity interests in these entities.

Petrochemical Services

Our Petrochemical Services business segment reflects the operations of our Lou-Tex Propylene Pipeline and Sabine Propylene Pipeline. These pipelines provide for the transportation of polymer-grade and chemical-grade propylene in Texas and Louisiana. Polymer-grade propylene is used in the manufacture of polypropylene. Chemical-grade propylene is a basic petrochemical used in plastics, synthetic fibers and foams.

The following information highlights the general use of our Lou-Tex Propylene and Sabine Propylene pipelines, both of which we operate:

- The *Lou-Tex Propylene Pipeline* is a 267-mile pipeline used to transport chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Shell Oil Company ("Shell") and Exxon Mobil are the only customers of this pipeline. The chemical-grade propylene we transport for Shell originates at its underground storage facility located in Sorrento, Louisiana and is delivered to various receipt points between Sorrento, Louisiana and Mont Belvieu, Texas. The chemical-grade propylene we transport for Exxon Mobil originates from its refining and chemical complex located in Baton Rouge, Louisiana and is delivered to either Exxon Mobil's customers or to an underground storage well located in Mont Belvieu, Texas owned by Mont Belvieu Caverns.

- The *Sabine Propylene Pipeline* consists of a 21-mile pipeline used to transport polymer-grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana. Shell is the sole customer of this pipeline. The polymer-grade propylene transported for Shell originates from the TOTAL/BASF Port Arthur cracker facility and is delivered to the Lyondell Basell polypropylene facility in Lake Charles, Louisiana.

As a result of the DEP I drop down transaction, we own a 66% equity interest in Lou-Tex Propylene and Sabine Propylene. EPO owns the remaining equity interests in these entities.

Revenues recorded for the Lou-Tex Propylene Pipeline and Sabine Propylene Pipeline are primarily based on exchange agreements with Shell and Exxon Mobil. As a result of these exchange agreements, we agree to receive propylene in one location and deliver propylene at another location for a fee. The following information summarizes the exchange agreements with Shell and Exxon Mobil:

- *Shell Exchange Agreements*. Shell is obligated to meet minimum delivery requirements under the Lou-Tex Propylene and Sabine Propylene agreements. If Shell fails to meet such minimum delivery requirements, it is obligated to pay a deficiency fee to us. The term of the Lou-Tex Propylene exchange agreement expires in March 2020 and the term of the Sabine Propylene exchange agreement expires in November 2011. The Lou-Tex exchange agreement will continue on a year-to-year basis after expiration, subject to termination by either party. The fees paid by Shell under the Lou-Tex Propylene exchange agreement are generally fixed and are adjusted annually based on the operating costs of the pipeline and the U.S. Departmen t of Labor wage index. During 2009, Shell provided notice of its intent to terminate the Sabine Propylene exchange agreement in November 2011. Given the importance of the Sabine Propylene Pipeline in delivering feedstocks to facilities connected to this pipeline, we believe that the Sabine Propylene Pipeline will remain commercially viable after the Shell exchange agreement expires in 2011.

- *Exxon Mobil Exchange Agreement*. The term of the Lou-Tex Propylene Pipeline exchange agreement expired in June 2008, but continues on a monthly basis subject to a two-year termination notice initiated by either party. The exchange fees paid by Exxon Mobil are based on the volume of chemical-grade propylene delivered.

Our propylene transportation business exhibits little seasonality. With respect to competition, our petrochemical pipelines are in single product service due to the required purity of the product being shipped. Because there are no other pipelines in our market area that ship the same dedicated purity-grade product, competition for this service is limited. In the future, a competitor could change service of an existing pipeline to ship such purity products, but would incur additional costs to connect their systems to our customers.

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 system. Since the operating balance is dependent upon the demand levels at various delivery points, the exact capacity of our petrochemical pipelines cannot be reliably determined. We measure the utilization rates of our petrochemical pipelines in terms of average throughput. Total average throughput volumes for these pipelines were 35 MBPD, 30 MBPD and 35 MBPD during the years ended December 31, 2010, 2009 and 2008, respectively.

Title to Properties

Our real property holdings fall into two basic categories: (1) parcels that we own in fee, such as the land and underlying storage caverns at Mont Belvieu, Texas and (2) parcels in which our interest derives 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 have no knowle dge 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. The Lou-Tex Propylene and Sabine Propylene pipelines are interstate common carrier pipelines regulated under the Interstate Commerce Act ("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.

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 nond iscriminatory. Shippers may challenge our intrastate tariff rates and practices on our pipelines. Our intrastate liquids pipelines are subject to regulation in Texas.

Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in Louisiana and Texas. Certain of our intrastate natural gas pipelines are also subject to limited regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Policy Act of 1978 ("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 distrib ution company served by an interstate pipeline without becoming subject to the FERC's jurisdiction under the Natural Gas Act of 1938 ("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 compliant with the FERC's regulations. The rates for 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 the Statement of Operating Conditions ("SOC") for the transportation and storage services provided by Enterprise Texas. 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 agreem ent, 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 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 EPO's 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.

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 requir ed 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.

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 ("EPCRA"); 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 a nd 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 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 curre ntly 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 li mit 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.

Climate Change Regulation

Responding to scientific studies that have 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 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. 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 r eached 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 fut ure 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 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, 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 Ci rcuit 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 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 as to 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 from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Chan ges 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 on energy markets or the physical 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 reg ulated waters. The EPA has also adopted regulations that require 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 prohibits 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 United States Coast Guard (“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 effects 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.

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 previous ly 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 U.S. Department of Transportation (“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. In addition, we are subject to a 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. The regulation establishes qualification requirements for individuals performing covered tasks.& #160; We believe we are in material compliance with these DOT regulations.

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

The DOT recently issued several new proposals to increase safety standards for pipelines. In June 2010, the DOT issued a Notice of Proposed Rulemaking that proposes to amend the pipeline safety regulations to apply the regulations to rural low-stress hazardous liquid pipelines that are not covered by the regulations in 49 CFR Part 195. The proposed rule would apply to all small-diameter (less than 8 5/8 inches) rural low-stress pipelines located within a 1/2 mile of an Unusually Sensitive Area ("USA") and to all rural low-stress pipelines of any diameter located outside the 1/2 mile USA buffer. The DOT also issued an Advance Notice of Proposed Rulemaking in October 2010 in which it& #160;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 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 "Relationship with EPCO" 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 1,900 EPCO personnel that spend all or a portion of their time engaged in our business. Approximately 400 of these individuals devote all of their time performing administrative, commercial and o perating duties for us. The remaining approximately 1,500 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 1-800-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.deplp.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.

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

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 that includes transporting and storing natural gas, NGLs and propylene. 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 and volumes transported by us and related to transportation and storage handling fees. We may also incur price risk to the extent counterparties do not perform in connection with our marketing of natural gas, NGLs and/or propylene.

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 NYMEX daily settlement price for natural gas 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. These factors include:

- § the level of domestic production and consumer product demand;
- § the availability of imported natural gas and actions taken by foreign oil and natural gas providing nations;
- § the availability of transportation systems with adequate capacity;
- § the availability of competitive fuels;
- § fluctuating and seasonal demand for 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 indirectly exposed to natural gas and NGL commodity price risk. An increase in natural gas prices or a decrease in NGL prices could result in a decrease in the volume of NGLs fractionated by our

Shoup and Armstrong fractionators, which would result in a decrease in gross operating margin for the South Texas NGL System.

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

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

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

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

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

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

Any decrease in supplies of natural gas could adversely affect our business and operating results. Our success depends on our ability to obtain access to new sources of natural gas from both domestic production and LNG terminals, which sources are dependent on factors beyond our control.

We cannot give any assurance regarding the natural gas production industry's ability to find new domestic supply sources. Production from existing wells and gas supply basins connected to our pipelines will naturally decline over time, which means our cash flows associated with the gathering or transportation of gas from these wells and basins will also decline over time. The amount of natural gas reserves underlying these wells may also be less than we anticipate, and the rate at which production from these reserves declines may be greater than we anticipate. Accordingly, to maintain or increase throughput levels on our pipelines, we must continually obtain access to new supplies of natural gas. The primary factors affecting our ability to obtain new sources of natural gas to our pipe lines include:

§ the level of successful drilling activity near our pipelines;

§ our ability to compete for these supplies;

§ our ability to connect our pipelines to the suppliers;

§ the successful completion of new liquefied natural gas ("LNG") facilities near our pipelines; and

§ our gas quality requirements.

The level of drilling activity depends on economic and business factors beyond our control. The primary factor that impacts drilling decisions is the price of oil and natural gas. These commodity prices have fluctuated dramatically in recent years. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our pipelines, which would lead to reduced throughput levels on our pipelines. Other factors that impact production decisions include producers' capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits, the availability and cost of drilling rigs and other drilling equipment and regulatory changes. Because of these factors, even if new natural gas reserves were discovered in areas served by our pipelines, producers may choose not to develop those reserves or may connect them to different pipelines.

Imported LNG is expected to be a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies is expected to be imported through LNG facilities which have currently been developed or new LNG facilities which 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, unanticipated 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 we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing supply basins, or if the expected increase in natural gas supply through imported LNG is not realized, throughput on our pipelines would decline, which could have a material adverse effect on our financial position, results of operations and ability to make distributions to our unitholders.

Consistent with industry practice, we do not obtain independent evaluations of natural gas reserves dedicated to our pipeline systems, including our South Texas NGL Pipeline & Storage System. Accordingly, volumes of natural gas gathered on our pipeline systems in the future could be less than we anticipate, which could adversely affect our cash flow and our ability to make cash distributions to unitholders.

Consistent with industry practice, we do not obtain independent evaluations of natural gas reserves connected to our pipeline systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems (or to processing and fractionation facilities such as those serving EPO in South Texas) or the anticipated lives of such reserves. If the total reserves or estimated lives of the reserves connected to our pipeline systems, particularly in South Texas, are less than we anticipate and we are unable to secure additional sources of natural gas or NGLs, then the volumes of NGLs transported on our NGL pipelines in South Tex as or natural gas gathered on our Acadian Gas System and other pipeline systems in the future could be less than we anticipate. A decline in the volumes of natural gas or NGLs gathered on our pipeline systems could have an adverse effect on our business, results of operations, financial position and our ability to make cash distributions to our unitholders.

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

Even if 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, market, 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 transportation businesses compete with other pipeline companies in the areas they serve. We also compete with truck, railroad and marine transportation companies in some of the areas we serve. Competitive pressures may adversely affect our tariff rates or volumes shipped.

In our natural gas gathering business, we encounter competition in obtaining contracts to gather natural gas supplies, and 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 is provided under bank facilities that mature in 2011 and 2013. The cost to refinance these facilities may be materially higher. Our debt level may limit our future financial and operating flexibility.

As of December 31, 2010, we had $106.0 million of indebtedness outstanding under our Multi-Year Revolving Credit Facility, which matures in October 2013, with the ability to borrow up to an additional $744.0 million, subject to certain conditions and limitations, under the credit agreement. We also had an additional $282.3 million of indebtedness outstanding under our senior unsecured Term Loan Agreement, which matures in December 2011 and $400.0 million of indebtedness outstanding under our $400 Million Term Loan Facility, which matures in October 2013. Our level of indebtedness could have important consequences, including:

§ 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;

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

§ we may need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operation, future business opportunities and distributions to unitholders; and

§ our debt level may make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which may be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisition, investments or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms if at all.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial position.

We have exposure to increases in interest rates. At December 31, 2010 we had $788.3 million in outstanding variable rate debt. As a result, significant increases in interest rates could adversely affect our results of operations, cash flows and financial position.

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.

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, to provide more stable cash flow. We consider and pursue potential joint ventures, stand alone 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.

The negative impact of the tightening of the credit markets may have a material adverse effect on us resulting from, but not limited to, an inability to expand facilities or finance the acquisition of assets on favorable terms, if at all, increased financing costs or financing with increasingly restrictive covenants. In addition, the distribution yields of new equity issued may be higher than our historical levels, making additional equity issuances more expensive.

We also compete for the types of assets and businesses we would likely be interested in purchasing or acquiring. 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 credit agreements contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond our control, or that may limit our business and/or financing activities.

The operating and financial restrictions and covenants in our credit agreements and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, our credit agreements may restrict or limit our ability to:

§ make distributions if any default or event of default occurs;

§ incur additional indebtedness or guarantee other indebtedness;

§ grant liens or make certain negative pledges;

§ make certain loans or investments;

§ make any material change to the nature of our business, including consolidations, liquidations and dissolutions; or

§ enter into a merger, consolidation, sale and leaseback transaction or sale of assets.

Our ability to comply with the covenants and restrictions contained in our credit agreements may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit agreement, a significant portion of our indebtedness may become immediately due and payable, and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Restrictions in our credit agreements could limit our ability to make distributions upon the occurrence of certain events.

Our payment of principal and interest on our debt will reduce cash available for distributions on our common units. Furthermore, our credit agreements could limit our ability to make distributions upon the occurrence of the following events, among others:

§ failure to pay any principal, interest, fees, expenses or other amounts when due;

§ failure of any representation or warranty made by us in our credit agreements to be true and correct in any material respect;

§ failure to perform or otherwise comply with the covenants in the credit agreements;

§ failure to pay any other material debt;

§ a bankruptcy or insolvency event involving us, our general partner or any of our subsidiaries;

§ the entry of, and failure to pay, one or more adverse judgments in excess of a specified amount against which enforcement proceedings are brought or that are not stayed pending appeal;

§ a change in control of us;

§ a judgment default or a default under any material agreement if such default could have a material adverse effect on us; and

§ the occurrence of certain events with respect to employee benefit plans subject to the Employee Retirement Income Security Act.

Any subsequent refinancing of our current debt or any new debt could have similar or more restrictive provisions. For more information regarding our credit agreements, see Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our pipeline integrity program 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 what the rules refer to as “high consequence areas.” 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 associate d 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 “high consequence areas” 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.

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 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 results of operations, cash flows and financial position. 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, accretion and amortization 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 results of operations, cash flows and financial position. In addition, any anticipated benefits of material acquisition, such as expected cost savings, may not be fully realized, if at all.

Because our general partner does not own incentive distribution rights in our distributions, we may elect to acquire or build energy infrastructure assets that have a lower expected return on investment than a similarly situated publicly traded energy partnership whose partner owns incentive distribution rights.

Duncan Energy Partners was formed in part to support the growth objectives of EPO. EPO, the owner of our general partner, elected to forgo incentive distribution rights with respect to our distributions for the purpose of reducing our expected long-term cost of equity capital. This should allow us to acquire or build energy infrastructure assets with lower expected returns on investment that should still be accretive, in terms of distributable cash flow, on a per unit basis. Such expected returns on investment may not be considered economically viable by other similarly situated publicly traded partnerships whose general partners own incentive distribution rights. In addition, we may elect to participate in capital projects with Enterprise, whe reby our expected return on investment may be lower than that of Enterprise, yet is still ultimately expected to be accretive, in terms of distributable cash flow, on a per unit basis for our common units. Should the returns and cash flow from operations from such acquisitions or capital projects not materialize as expected, we may not be able to support our cash distribution rate at current levels or increase our cash distribution rate to partners in the future.

We may not be able to make acquisitions or to make acquisitions on economically acceptable terms, which may limit our ability to grow.

We are limited in our ability to make acquisitions by our business opportunity agreements with EPO. These agreements entitle them to take business opportunities for the benefit of themselves before allowing us to take them. In addition, our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) unable to obtain financing for these acquisitions on economically acceptable terms, or (iii) outbid by competitors, then our future growth and ability to maintain and increase over time d istributions will be limited.

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.

We depend in large part on EPO and the continued success of its business as we operate our assets as part of their value chain, and adverse changes in its related businesses may reduce our revenue, earnings or cash available for distribution.

We have entered into a number of material contracts with EPO and its subsidiaries relating to midstream energy services and arrangements. Our cash flows and financial position depend in large part on the continued success of EPO as we operate our assets as part of its value chain. Any adverse changes in the business of EPO, due to market conditions, sales of assets or otherwise, or the failure of EPO to renew any of its material agreements with us, could reduce our revenue, earnings or cash available for distribution. See Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our relationship with EPO.

The interruption of distributions to us from our subsidiaries may affect our ability to satisfy our obligations and to make 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 subsidiaries. As a result, we depend upon the earnings and cash flow of our subsidiaries and Evangeline and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners. The ability of our subsidiaries and Evangeline to make 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.

We also own a membership interest in Enterprise Texas, which interest has a stated fixed return. Although we have effective priority rights to specified quarterly distribution amounts ahead of any distributions on EPO's minority equity interests in Enterprise Texas, the inability of Enterprise Texas Pipeline to make distributions of the fixed returns in full each quarter would have a material adverse impact on our ability to make distributions to our partners and could affect our ability to satisfy other debt obligations.

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

The credit and business risk profiles of a general partner or owners of a general partner may be factors in credit evaluations of a limited partnership by the nationally recognized debt rating agencies. This is because the general partner controls the business activities of the partnership, including its cash distribution policy and acquisition strategy and business risk profile. Another factor that may be considered is the financial position of our general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

If we were to seek a credit rating in the future, our credit rating may be adversely affected by the leverage of the owners of our general partner, as credit rating agencies may consider these entities' leverage because of their ownership interest in and control of us, the strong operational links between them and their affiliates and us, and our reliance on EPO for a substantial percentage of our revenue. Any such adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise money in the capital markets, which would impair our ability to grow our business and make distributions to unitholders.

Affiliates of EPCO and Enterprise, the indirect owner of our general partner, have significant indebtedness outstanding and are dependent principally on the cash distributions from their limited partner interests in Enterprise to service such indebtedness. Any distributions by Enterprise to such entities will be made only after satisfying their then-current obligations to their 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, and other entities controlled by EPCO, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of EPCO o r the entities that control our general partner were viewed as substantially lower or more risky than ours.

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 pounds per square inch. Pipelines may suffer inadvertent damage from construction, farm and utility equipment. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms and floods. 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 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. 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, accord ingly, adversely affect the market price of our common units.

We believe that EPCO maintains adequate insurance coverage on behalf of us, although insurance will not cover many types of interruptions that might occur and will not cover amounts up to applicable deductibles. As a result of market 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, changes 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 si gnificant 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. See Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for more information regarding insurance matters.

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. We cannot ensure that our construction projects will not be delayed due to government permits, weather conditions or other factors beyond our control. The construction of new assets also 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 or demand 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; 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.

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

The intrastate natural gas pipeline transportation services we provide are subject to various Texas and Louisiana 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, proposed and existing rates subject to state regulation and the provision of our services on a non-discriminatory basis are subject to challenge by protest and complaint, respectively. In addition, the transportation and storage services furnished by our intrastate natural gas facilities on behalf of interstate natural gas pipelines or certain local distribution companies are regulated by the FERC pursuant to Section 311 of the NGA. Pursuant to the NGA, we are required to offer those services on an open and nondiscriminatory basis at a fair and equitable rate. Such FERC-regulated NGA Section 311 rates also may be subject to challenge and successful challenges may adversely affect our revenues.

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, the distinction between FERC-regulated transmission service and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. 60; Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both federal and state 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.

The tariff rates and terms of service of the intrastate liquids pipeline transportation services we provide are subject to various Texas state laws and regulations. Although state regulation typically is less onerous than FERC regulation, our intrastate rates and terms of service are subject to challenge by complaint.

The STB regulates transportation on interstate propylene pipelines. The current version of the ICA and its implementing regulations give the STB authority to regulate the rates we charge for service on the propylene pipelines and generally requires that our rates and practices be just and reasonable and nondiscriminatory. The rates we charge for movements on our propylene pipelines may be subject to challenge and any successful challenge to those rates could adversely affect our revenues. Our interstate propylene pipelines formerly were regulated by the FERC, and we cannot guarantee that the FERC will not reassert jurisdiction over those facilities in the future.

For a general overview of federal, state and local regulation applicable to our assets, see Item 1 and 2 of this annual report.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could 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 resto re 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.

The EPA has also taken action under the CAA to regulate greenhouse gas 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, 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 EPA's PSD and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to re duce 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 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. 60;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 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 p anel 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 fo r 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.< /div>

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 othe rs 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, including litigation, to oil and gas drilling activities using hydraulic fracturing techniques. 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.

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 trans actions. 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 derivative contracts from time to time with respect to a portion of our expected storage 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 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 us 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 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. These requirements may affect the liquidity and pricing o f derivative contracts, and the costs of compliance by dealers and counterparties will likely be passed on to customers, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

We depend on EPO and certain other key customers for a significant portion of our revenues. The loss of any of these key customers could result in a decline in our revenues and cash available to make distributions to our unitholders.

We rely on a limited number of customers for a significant portion of revenues. For the year ended December 31, 2010, 2009 and 2008, EPO and its affiliates accounted for approximately 34.6%, 33.8% and 23.6% of our total consolidated revenues, respectively. In addition, several of our assets also rely on only one or two customers for the asset's cash flow. For example, the only shipper on the pipeline owned by South Texas NGL is EPO; there are only two customers on our Lou-Tex Propylene Pipeline; there is only one customer on our Sabine Propylene Pipeline; and there is only one shipper on the pipeline held by Evangeline. In order for new customers to use these pipelines, we or the new shippers would be req uired to construct interim pipeline connections.

We may be unable to negotiate extensions or replacements of these contracts and those with other key customers on favorable terms. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our financial position, results of operations and ability to make distributions to our unitholders, unless we are able to contract for comparable volumes from other customers at favorable rates.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks. We generally do not require collateral for our accounts receivable. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment or nonperformance by them could have a material adverse effect on our business, results of operations, financial position and ability to make cash distributions to our unithold ers.

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.

Successful development of LNG import terminals outside our areas of operations could reduce the demand for our services.

Development of new, or expansion of existing, LNG facilities outside our areas of operations could reduce the need for customers to transport natural gas from supply basins connected to our pipelines. This could reduce the amount of gas transported by our pipelines for delivery off-system to other intrastate or interstate pipelines serving these customers. If we are not able to replace these volumes with volumes to other markets or other regions, throughput on our pipelines would decline which could have a material adverse effect on our financial position, results of operations and ability to make distributions to our unitholders.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities are located, and we are therefore subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on our business, results of operations, financial position and ability to make distributions to our unitholders.

Mergers among our customers or competitors could result in lower volumes being shipped on our pipelines, thereby reducing the amount of cash we generate.

Mergers among our existing customers or competitors could provide strong economic incentives for the combined entities to utilize systems other than ours and we could experience difficulty in replacing lost volumes and revenues. Because most of our operating costs are fixed, a reduction in volumes would result in not only a reduction of revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and make distributions to our unitholders.

Risks Relating to an Investment in Us

Enterprise and its affiliates, EPO and EPCO and its affiliates may compete with us, and business opportunities may be directed by contract to those affiliates prior to us under the administrative services agreement.

Our partnership agreement does not prohibit Enterprise and its affiliates, EPO and EPCO and their affiliates, other than our general partner, from owning and operating natural gas and NGL pipelines and storage assets or engaging in businesses that otherwise compete directly or indirectly with us. In addition, Enterprise, EPO and EPCO may acquire, construct or dispose of additional midstream energy or other natural gas assets in the future, without any obligation to offer us the opportunity to purchase or construct any of these assets.

Under the ASA, if any business opportunity, other than a business opportunity to acquire general partner interests and other related equity securities in a publicly traded partnership, is presented to EPCO and its affiliates, us and our general partner, EPO or Enterprise and its general partner, then EPO will have the first right to pursue such opportunity for itself or, in its sole discretion, to affirmatively direct the opportunity to us. Accordingly, we are limited by contract in our ability to take certain business opportunities for our partnership. See Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report and Item 13 of this annual report for more information regarding the ASA.

Our general partner and its affiliates own a controlling interest in us and have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to our detriment.

As of December 31, 2010, EPO indirectly owned a 0.7% general partner interest in us and beneficially owned approximately 58.5% of our outstanding common units and controls our general partner, which controls us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage it and our general partner in a manner beneficial to Enterprise and its affiliates. Furthermore, certain directors and officers of our general partner may be directors or officers of affiliates of our general partner. Conflicts of interest may arise between Enterprise and its affiliates, including our general partner, on the one hand, and us and our unitho lders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These potential conflicts include, among others, the following situations:

§ Enterprise, EPCO and their affiliates may engage in substantial competition with us on the terms set forth in the ASA.

§ Neither our partnership agreement nor any other agreement requires EPCO or Enterprise or their affiliates (other than our general partner) to pursue a business strategy that favors us. Directors and officers of EPCO and the general partners of Enterprise and their affiliates have a fiduciary duty to make decisions in the best interest of their shareholders or unitholders, which may be contrary to our interests.

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

§ Some of the employees of EPCO who provide services to us also may devote significant time to the business of Enterprise and will be compensated by EPCO for such services.

§ Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders will be deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.

§ Our general partner determines the amount and timing of asset purchases and sales, operating expenditures, capital expenditures, borrowings, repayments of indebtedness, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders.

§ Our general partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us.

§ EPO may propose to contribute additional assets to us and, in making such proposal, the directors of EPO have a fiduciary duty to EPO's members and not to our unitholders.

§ Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable 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 obligations.

§ Our general partner may exercise its rights to call and purchase all of our common units if, at any time, it and its affiliates own 80% or more of the outstanding common units.

§ Our general partner controls the enforcement of obligations owed to us by it and its affiliates, including the ASA.

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

See Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report and Item 13 of this annual report for additional information regarding our relationships with EPCO and EPO.

We may be limited in our ability to consummate transactions, including acquisitions with affiliates of our general partner.

We will have inherent conflicts of interest with affiliates of our general partner, including Enterprise. These conflicts may cause the ACG Committees of these entities not to approve, or unitholders of these entities to dispute, any transactions that may be proposed or consummated between or among us and these affiliates. This may inhibit or prevent us from consummating transactions, including acquisitions, with them.

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 allocate their time among us, EPCO and other affiliates of EPCO. These officers 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 the ASA, which governs business opportunities among entities controlled by EPCO, which includes us and our general partner and Enterprise and its general partner. For information regarding how business opportunities are handled under the ASA 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.&# 160; 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.

An affiliate of EPO has the power to appoint and remove our directors and management.

Because EPO beneficially owns 100% of DEP GP, it has the ability to elect all the members of the board of directors of our general partner. Our general partner has control over all decisions related to our operations. Furthermore, the goals and objectives of EPO relating to us may not be consistent with those of a majority of the public unitholders.

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

If at any time after December 8, 2010, our general partner and its affiliates own 80% or more of our outstanding common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of:

- § the average of the daily closing prices of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed; and

- § the highest price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed.

As a result, our unitholders may be required to sell their common units at a price that is less than the initial offering price or, because of the manner in which the purchase price is determined, at a price less than the then current market price of our common units. In addition, this call right may be exercised at an otherwise undesirable time or price and unitholders may not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their common units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the call right. There is no restriction in our partnership agreement that prevents our general partner f rom issuing additional common units or other equity securities and exercising its call right. If our general partner exercised its call right, the effect would be to take us private and, if our common units were subsequently deregistered, we might no longer be subject to the reporting requirements of the Securities

Exchange Act of 1934, as amended, or the "Exchange Act". As of February 1, 2011, affiliates of Enterprise own our general partner and approximately 58.5% of our outstanding common units.

Our partnership agreement limits our general partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

§ permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its rights to vote or transfer our common units it owns, its registration rights and the determination of whether to consent to any merger or consolidation of the partnership, or amendment to the partnership agreement;

§ provides in the absence of bad faith by the ACG Committee or our general partner, the resolution, action or terms made, taken or provided in connection with a potential conflict of interest transaction will be conclusive and binding on all persons (including all partners) and will not constitute a breach of the partnership agreement or any standard of care or duty imposed by law;

§ provides the general partner shall not be liable to the partnership or any partner for its good faith reliance on the provisions of the partnership agreement to the extent it has duties, including fiduciary duties, and liabilities at law or in equity;

§ generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the ACG Committee of the board of directors of our general partner must be on terms no less favorable to us than those generally provided to or available from unrelated third parties or be "fair and reasonable" to us;

§ provides that it shall be presumed that the resolution of any conflicts of interest by our general partner or the ACG Committee was not made in bad faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

§ provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

By purchasing a common unit, a unitholder will become bound by the provisions of our partnership agreement, including the provisions described above.

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.

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 will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, is chosen entirely by its owners and not by the unitholders. Furthermore, even if our unitholders were dissatisfied with the performance of our general partner, they will, practically speaking, have a limited ability to remove our general partner. As a result of these limitations, the price at which our common units trade could be diminished because of the absence or reduction of a control premium in the trading price.

The vote of the holders of at least 66 2/3% of all outstanding common units is required to remove our general partner. As of February 1, 2011, affiliates of Enterprise, which owns our general partner, owned approximately 58.5% of our outstanding common units.

We may issue additional units without our unitholders' approval, which would dilute our unitholders' ownership interests.

At any time, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give unitholders the right to approve our issuance of equity securities ranking junior to our common units at any time. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to our common units. The issuance by us of additional common units or other equity securities will have the following effects:

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

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

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

§ the ratio of taxable income to distributions may increase; and

§ the market price of our common units may decline.

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

Our partnership agreement restricts unitholders' voting rights by providing that any common units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting common unitholders' ability to influence the manner or direction of management.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions to our unitholders.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets, other than the ownership interests, in our subsidiaries and Evangeline. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and Evangeline and their ability to distribute funds to us. The ability of our subsidiaries and Evangeline to make 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.

Affiliates of Enterprise currently own a 34% minority equity interest in certain of our operating subsidiaries and a 49% equity interest in our remaining operating subsidiaries. These affiliates have a right of first refusal to acquire these subsidiaries or their material assets if we desire to sell them, other than inventory and other assets sold in the ordinary course of business. These rights may adversely affect our ability to dispose of these assets. In addition, Duncan Energy Partners' ownership interest in Mont Belvieu Caverns may be diluted, and the cash flow from our NGL Pipelines & Services segment may be reduced, if

Duncan Energy Partners does not contribute a proportionate share of certain future costs to fund expansion projects at Mont Belvieu Caverns.

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 direct 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 to EPCO and its affiliates will reduce cash available for distribution to our unitholders.

Prior to making any distribution on our common units, we will reimburse EPCO and its affiliates for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts could adversely affect our ability to make distributions to our unitholders. 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.

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

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. Unitholders 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
- unitholders' 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, 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 l iable 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 may transfer its general partner interest to a third-party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of DEP GP or EPO to transfer their 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.

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 distributions to our 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.

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 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.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us 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 or our operating subsidiaries, 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, 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. 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.

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 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. 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 common unitholders' 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 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 own property or conduct business in Louisiana and Texas. We may own property or conduct business in other states or foreign countries in the future. It is the r esponsibility of each unitholder to file its own federal, state and local tax returns.

The sale or exchange of 50% or more of the total interest in our capital and profits 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 would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year. Our technical termination could also result in a 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 DEP GP 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 DEP GP. 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 DEP GP, 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 of the Section 743(b) ad justment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between DEP GP 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, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because 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 o f 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 a defendant 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 17 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).

PART II

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

Market Information and Cash Distributions

Our common units are listed on the NYSE under the ticker symbol "DEP." As of February 1, 2011, there were approximately 47 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods indicated (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.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2009					
1st Quarter	$ 18.07	$ 13.55	$ 0.4300	April 30, 2009	May 8, 2009
2nd Quarter	$ 20.15	$ 14.75	$ 0.4350	July 31, 2009	August 7, 2009
3rd Quarter	$ 20.00	$ 15.91	$ 0.4400	October 30, 2009	November 5, 2009
4th Quarter	$ 24.19	$ 19.19	$ 0.4450	January 29, 2010	February 5, 2010
2010					
1st Quarter	$ 27.25	$ 22.08	$ 0.4475	April 30, 2010	May 6, 2010
2nd Quarter	$ 28.56	$ 22.27	$ 0.4500	July 30, 2010	August 6, 2010
3rd Quarter	$ 31.20	$ 26.04	$ 0.4525	October 29, 2010	November 8, 2010
4th Quarter	$ 33.39	$ 30.50	$ 0.4550	January 31, 2011	February 7, 2011

The quarterly cash distributions per unit shown in the preceding table correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our common unitholders) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to common unitholders primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under Item 7 of this annual report. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2010 that have not been previously reported. We did not repurchase any of our common units during the year ended December 31, 2010.

Common Units Authorized for Issuance Under Equity Compensation Plans

On December 30, 2009, the 2010 Duncan Energy Partners L.P. Long-term Incentive Plan ("2010 Plan") and DEP Unit Purchase Plan ("EUPP") were approved by written consent of a holder of a majority of our common units and became effective upon filing of a registration statement on Form S-8 with the SEC in February 2010. For more information about the 2010 Plan and EUPP, see Note 5 of the Notes to Consolidated Financial Statements included in Item 8 of this annual report. 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.

Item 6. *Selected Financial Data*.

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from and should be read in conjunction with our audited financial statements included under Item 8 of this annual report. Information regarding our consolidated 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 the Year Ended December 31,				
	2010	2009	2008	2007	2006
Operating Results Data:					
Revenues	$ 1,115.1	$ 979.3	$ 1,598.1	$ 1,220.3	$ 1,263.0
Net income	53.4	45.8	55.3	23.6	51.7
Net loss (income) attributable to noncontrolling interest (1)	36.7	45.3	(7.4)	(20.0)	--
Net income attributable to Duncan Energy Partners L.P.	90.1	91.1	47.9	3.6	51.7
Allocation of net income attributable to Duncan Energy Partners L.P.:					
Limited partners of Duncan Energy Partners	$ 89.5	$ 90.5	$ 27.8	$ 18.8	$ n/a
General partner of Duncan Energy Partners	0.6	0.6	0.5	0.4	n/a
Former owner of DEP II Midstream Businesses	n/a	n/a	19.6	(20.6)	(3.7)
Former owner of DEP I Midstream Businesses	n/a	n/a	n/a	5.0	55.3
Basic and diluted earnings per unit	$ 1.55	$ 1.57	$ 1.22	$ 0.93	n/a
Cash distributions per common unit (2)	$ 1.81	$ 1.75	$ 1.68	$ 1.46	n/a
Financial position data:					
Total assets (3)	$ 5,571.9	$ 4,770.8	$ 4,594.7	$ 3,983.3	$ 3,798.4
Total debt obligations (4)	788.3	457.3	484.3	200.0	n/a
Former owner's equity in DEP II Midstream Businesses (5)	n/a	n/a	n/a	2,880.1	2,853.8
Former owner's equity in DEP I Midstream Businesses (5)	n/a	n/a	n/a	n/a	725.8
Equity (6)	4,519.6	4,136.9	3,844.2	669.9	n/a
Total common units outstanding (7)	57.7	57.7	57.7	20.3	n/a

(1) Represents EPO's share of the earnings of the DEP I and DEP II Midstream Businesses following the drop down of each set of businesses to Duncan Energy Partners. The DEP I drop down transaction was effective February 1, 2007 for financial accounting and reporting purposes. The DEP II drop down transaction was effective December 8, 2008.

(2) Represents cash distributions declared by Duncan Energy Partners since its initial public offering in February 2007.

(3) Total assets have increased since our initial public offering due to capital spending.

(4) Represents our DEP Multi-Year Revolving Credit Facility, $400 Million Term Loan Facility, Revolving Credit Facility and Term Loan Agreement, as applicable, for the periods in which Duncan Energy Partners had borrowings outstanding under each agreement. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding these debt obligations.

(5) Represents the net assets of the combined DEP I or DEP II Midstream Businesses (as applicable) prior to the date they were contributed to Duncan Energy Partners.

(6) Represents the noncontrolling interest in subsidiaries, limited and general partner capital accounts and related accumulated other comprehensive income of Duncan Energy Partners since February 2007.

(7) The amount presented for December 31, 2008 includes 37.3 million Class B units that converted to common units on February 1, 2009.

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.
- § Supplemental Selected Financial Information of Duncan Energy Partners L.P. – Discusses financial information and sources and uses of cash for Duncan Energy Partners L.P. on a standalone basis.
- § 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 all other matters.

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("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," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Althoug h 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 publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." We were formed in September 2006 and did not own any assets prior to February 5, 2007, which was the date we completed our initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. Our business purpose is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. We are engaged in the business of: (i) NGL transportation, fractionation and marketing; (ii) storage of NGL, petrochemical and refined products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas.

At December 31, 2010, we were owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP. EPO beneficially owned approximately 58.5% of our common units and 100% of DEP GP at December 31, 2010. DEP GP is responsible as general partner for managing our business and operations. EPCO provides all of our employees and certain administrative services to us.

See "Significant Recent Developments" within this Item 7 for information regarding Enterprise's February 22, 2011 offer to acquire all of our outstanding publicly-held common units.

Our relationship with EPO is one of our principal business advantages. Our assets connect to various midstream energy assets of EPO and form integral links within EPO's value chain of assets. We believe that the operational significance of our assets to EPO, as well as the alignment of our respective economic interests in these assets, will result in a collaborative effort between us and EPO to promote the operational efficiency of our assets and maximize their value. See Item 13 within this annual report and Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our extensive and ongoing relationships with EPO and EPCO.

We have three reportable business segments: Natural Gas Pipelines & Services; NGL Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

DEP I Drop Down

Effective February 1, 2007, EPO contributed to us a 66% controlling equity interest in each of the DEP I Midstream Businesses in a drop down transaction. EPO retained the remaining 34% noncontrolling equity interest in each of these businesses. As consideration for these equity interests, we paid $459.5 million in cash and issued 5,351,571 common units to EPO. The cash portion of this consideration was financed with $198.9 million in borrowings under our Revolving Credit Facility and $260.6 million of the $290.5 million of net proceeds from our initial public offering. See Item 1 and 2 of this annual report for a description of the assets and operations of the DEP I Midstream Businesses.

DEP II Drop Down

On December 8, 2008, EPO contributed to us the following controlling equity interests in a second drop down transaction: (i) a 66% voting general partner interest in Enterprise GC, (ii) a 51% voting general partner interest in Enterprise Intrastate and (iii) a 51% voting membership interest in Enterprise Texas. As consideration for these equity interests, we paid $280.5 million in cash and issued 37,333,887 Class B units to EPO (which automatically converted on a one-for-one basis to common units in February 2009). The cash portion of this consideration was financed with $280.0 million in borrowings under our Term Loan Agreement and $0.5 million of net proceeds from an equity offering to EPO. The market value of the Class B un its at the time of issuance was approximately $449.5 million. See Item 1 and 2 of this annual report for a description of the assets and operations of the DEP II Midstream Businesses. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the Term Loan Agreement.

Noncontrolling Interests

For detailed information regarding EPO's noncontrolling interest in the DEP I and DEP II Midstream Businesses, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Basis of Presentation

See Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the basis for presentation of our general purpose financial statements. Such information is incorporated by reference into this Item 7 discussion.

Supplemental Selected Financial Information of Duncan Energy Partners L.P.

We are providing the following selected financial information to assist investors and other users of our financial statements in understanding the principal sources and uses of cash flows of Duncan Energy Partners L.P. on a standalone basis. Duncan Energy Partners L.P. has no operations apart from its investing activities and indirectly overseeing the management of the DEP I and DEP II Midstream Businesses.

The primary sources of cash flow for Duncan Energy Partners L.P. are the cash distributions it receives from the DEP I and DEP II Midstream Businesses. The primary cash requirements of Duncan Energy Partners are for general and administrative costs, debt service and distributions to partners. The amount of cash distributions that Duncan Energy Partners L.P. is able to pay its unitholders may fluctuate based on the level of distributions it receives from its operating subsidiaries. Factors such as capital contributions, debt service requirements, general and administrative costs, reserves for future distributions and other cash reserves established by the board of directors of our general partner (the "Board") may also affect the distributions Duncan Energy Partners L.P. makes to its unitholders.

For purposes of this presentation, we have provided information pertaining to the DEP I Midstream Businesses apart from those of the DEP II Midstream Businesses. Amounts presented for the DEP II Midstream Businesses for fiscal year 2008 represent the period from December 8, 2008 to December 31, 2008.

	For the Year Ended December 31,		
	2010	2009	2008
		(dollars in millions)	
Selected income statement information:			
Equity in income - DEP I Midstream Businesses	$ 47.8	$ 44.9	$ 37.2
Equity in income - DEP II Midstream Businesses	$ 56.0	$ 60.1	$ 4.5
General and administrative costs	$ 1.8	$ 0.4	$ 1.4
Interest expense	$ 11.9	$ 13.5	$ 12.0
Net income attributable to partners	$ 90.1	$ 91.1	$ 28.3
Selected balance sheet information at each period end:			
Investments in DEP I Midstream Businesses (1)	$ 854.6	$ 510.2	$ 512.7
Investments in DEP II Midstream Businesses	$ 677.6	$ 709.7	$ 730.5
Total debt obligations	$ 788.3	$ 457.3	$ 484.3
Partners' equity	$ 760.4	$ 761.4	$ 752.8

(1) The $344.4 million increase since December 31, 2009 is primarily due to our funding of the Haynesville Extension.

The following table presents the amount of distributions paid by each group of businesses with respect to each period.

	For the Year Ended December 31,		
	2010	2009	2008
		(dollars in millions)	
Distributions paid to Duncan Energy Partners L.P. with respect to each period from:			
DEP I Midstream Businesses	$ 46.5	$ 49.2	$ 93.7
DEP II Midstream Businesses	$ 88.2	$ 86.5	$ 5.6

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (the “Tier I distribution,” based on our $730.0 million aggregate investment) and then to EPO (the “Tier II distribution”), in amounts sufficient to generate an annualized return to both owners based on their respective investments. Distributions in excess of these amounts (the “Tier III distributions”) will be allocated 98% to EPO and 2% to us.

The initial annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, which was based on our estimated weighted-average cost of capital at December 8, 2008 plus 1.0%. The annualized return rate increases by 2.0% on January 1 of each year. As a result, the annualized return rate for 2010 was 12.087% and for 2011 will be 12.329%. If we participate in an expansion capital project involving the DEP II Midstream Businesses, we may request an incremental adjustment to the then-applicable annualized return rate to reflect our weighted-average cost of capital associated with such contribution.

The annualized return rate is applied to each party’s aggregate investment (or “Distribution Base”) in the DEP II Midstream Businesses. To the extent that we and/or EPO make capital contributions to fund expansion capital projects involving the DEP II Midstream Businesses, the Distribution Base of the contributing member will be increased by that member’s capital contribution at the time such contribution is made. Our Distribution Base has remained at $730.0 million from December 8, 2008 through December 31, 2010. EPO’s Distribution Base was $452.1 million, $817.9 million and $1.1 billion at December 8, 2008, December 31, 2009 and December 31, 2010, respectively. The increase in EPO’s Distribution Base is the result of its decision to fund 100% of the expansion capital project costs of the DEP II Midstream Businesses since December 8, 2008. For the year ended December 31, 2010, EPO funded $320.2 million of expansion capital spending for the DEP II Midstream Businesses. This spending was primarily attributable to natural gas pipeline projects in the Barnett Shale resource basin (e.g., completion of the Trinity River Lateral in July 2010) and ongoing expansions of our pipeline network in the Eagle Ford Shale region. Although we have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, we may elect to invest in existing or future expansion projects at a later date.

We and EPO received $88.2 million and $46.1 million, respectively, in cash distributions from the DEP II Midstream Businesses for the twelve months ended December 31, 2010. The $88.2 million (or, approximately, $22.1 million each quarter) received by us with respect to 2010 represents the annualized return rate for 2010 of 12.087% multiplied by our Distribution Base of $730.0 million. As a result, we received our expected Tier I distributions for the period. Based on EPO’s Distribution Base throughout 2010, it was entitled to $121.9 million of Tier II distributions, of which it received only $46.1 million. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to 2010.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity’s percentage interest of 22.6% and 77.4%, respectively, and then in a manner that in part follows the cash distributions paid by (or contributions made to) each DEP II Midstream Business. The 22.6% and 77.4% amounts represent each owner’s initial relative economic investment in the DEP II Midstream Businesses at December 8, 2008. Under our income sharing arrangement with EPO, we are allocated additional income (in excess of our percentage interest) to the extent that the cash distributions we receive (or contributions made) exceed the amount we would have been entitled to receive (or required to fund) based solely on our percentage interest. &# 160;This additional earnings allocation to us reduces the amount of income allocated to EPO by an equal amount and may result in EPO being allocated a loss when we are allocated income. It is our expectation that EPO will be allocated a loss by the DEP II Midstream Businesses until such time as expansion capital projects such as the Sherman Extension and Trinity River Lateral realize their income and cash flow potential. Our participation in the expected future increase in cash flow from such projects is limited (beyond our annualized return amount) to 2% of such upside, with EPO receiving 98% of the benefit.

For additional information regarding the allocation of net income (or loss) of the DEP II Midstream Businesses, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

For information regarding the non-cash depreciation, amortization and accretion amounts of the DEP I and DEP II Midstream Businesses on a 100% basis, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Significant Recent Developments

The following information highlights specified 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.

Enterprise Offers to Acquire Publicly-Held Common Units of 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 our 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 of our outstanding publicly-held common units as part of a transaction that would be structured as a merger between us 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 percent, based on the 10-day average closing price of our common units and the closing price of Enterprise common units on February 18, 2011. If the proposed merger is approved, E nterprise 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 Facility

On February 8, 2011, a fire occurred at our Mont Belvieu, Texas underground 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. T he Mont Belvieu underground storage facility is owned by Mont Belvieu Caverns, which is owned 66% by Duncan Energy Partners and 34% by EPO. 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.

DEP Multi-Year Revolving Credit Facility and $400 Million Term Loan Facility

In October 2010, we entered into a Revolving Credit and Term Loan Agreement. The new credit facilities mature in October 2013 and consist of: (i) the DEP Multi-Year Revolving Credit Facility and (ii) the $400 Million Term Loan Facility. At closing in October 2010, we borrowed the full amount available under the $400 Million Term Loan Facility to repay principal amounts outstanding under our then existing Revolving Credit Facility and the Loan Agreement with EPO. Upon repayment, of the principal amounts outstanding, both the Revolving Credit Facility and the Loan Agreement with EPO were terminated. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding t he Revolving Credit and Term Loan Agreement.

We entered into these new credit facilities primarily to fund our capital spending requirements under the Haynesville Extension project. See “Segment Discussion – Natural Gas Pipelines & Services” included under Item 1 and 2 of this annual report for additional information regarding our Haynesville Extension project. Variable interest rates charged under the new credit facilities are based on LIBOR or a base rate, both as defined in the Revolving Credit and Term Loan Agreement.

Expansion of Shoup and Armstrong Fractionation Facilities

In May 2010, we and EPO 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 Shale supply basin. In June 2010, we completed modifications to our Shoup facility, which increased its NGL fractionation capacity to 77 MBPD. In January 2011, we completed modifications to infrastructure at the Armstrong facility, which increased its NGL fractionation capacity to 20 MBPD. The $24 million aggregate cost of these expansion projects was funded entirely by EPO.

Registration Statements and Equity Offerings

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 common units in connection with the EUPP and the 2010 Plan, which became effective on February 11, 2010.

General Outlook for 2011

Commercial Outlook

We provide midstream energy services to producers and consumers of natural gas, NGLs, 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) in the United States 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 resourc e 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 U.S. 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 mill ion 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 our NGL fractionators, pipelines and storage facilities operating at high utilization rates and (ii) to provide us with opportunities to invest capital to build new natural gas 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 cou nt 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 provid ing 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.

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 and transport 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 and storage and NGL fractionation facilities to facilitate production growth from this region. These projects represent approximately $1.1 billion of capital expenditures in the aggregate from 2010 through 2013. These expansions are being made to assets that are principally DEP II assets, and EPO plans to fund the majority of the capital expenditures associated with these projects.

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 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 of which we will fund our 66% share.

Liquidity Outlook

The corporate debt and equity capital markets continued to improve in 2010. The cost of our equity capital has generally declined to pre-financial crisis levels or less. The availability of term debt and equity capital has also improved.

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 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 2010 through 2014. The interest rate on U.S. Treasury debt has an 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 t he cost and availability of capital.

At December 31, 2010, we had liquidity (unrestricted cash and availability under credit facilities) of approximately $763 million. All of our debt is comprised of floating rate debt. We currently estimate that our share of capital expenditures to fund for 2011 will approximate $640 million, which includes approximately $625 million for growth capital projects (principally our share of the Haynesville Extension project) and $15 million for sustaining capital expenditures. 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. As of Dece mber 31, 2010, we were in compliance with our loan covenant obligations.

Our $282.3 million term loan facility matures in December of 2011. The $850.0 million multi-year revolving credit facility and $400.0 million term loan facility that we executed in October 2010 will each mature in October 2013. We currently believe we will have sufficient liquidity and access to capital markets to refinance these facilities.

Results of Operations

Selected Volumetric Data

The following table presents average throughput and fractionation volumes for our principal pipelines and facilities. These statistics are presented in total for each asset (or asset group) irrespective of ownership interest (i.e., on a 100% basis), with the exception of pipeline throughput volumes for Evangeline (a component of the Acadian Gas System), which we report on a net basis to our ownership interest.

	For the Year Ended December 31,		
	2010	2009	2008
Natural Gas Pipelines & Services, net:			
Natural gas throughput volumes (BBtus/d)			
Texas Intrastate System	3,898	3,902	4,021
Acadian Gas System:			
Transportation volumes	455	436	378
Sales volumes (1)	339	320	331
Total natural gas throughput volumes	4,692	4,658	4,730
NGL Pipelines & Services, net:			
NGL throughput volumes (MBPD)			
South Texas NGL System - Pipelines	124	109	126
NGL fractionation volumes (MBPD)			
South Texas NGL System - Shoup and Armstrong fractionators	79	77	80
Petrochemical Services, net:			
Propylene throughput volumes (MBPD)			
Lou-Tex Propylene Pipeline	23	21	25
Sabine Propylene Pipeline	12	9	10
Total propylene throughput volumes	35	30	35

(1) Includes average net sales volumes for Evangeline of 47 BBtus/d for the year ended December 31, 2010 and 50 BBtus/d for each of the years ended December 31, 2009 and 2008, respectively.

Comparison of Results of Operations

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

	For the Year Ended December 31,		
	2010	2009	2008
Revenues	$ 1,115.1	$ 979.3	$ 1,598.1
Operating costs and expenses	1,030.4	908.3	1,512.8
General and administrative costs	20.0	11.2	18.3
Equity in income of Evangeline	0.8	1.1	0.9
Operating income	65.5	60.9	67.9
Interest expense	12.1	14.0	12.0
Net income	53.4	45.8	55.3
Net loss (income) attributable to noncontrolling interest:			
DEP I Midstream Businesses – Parent	(27.7)	(15.3)	(11.4)
DEP II Midstream Businesses – Parent	64.4	60.6	4.0
Net income attributable to Duncan Energy Partners	90.1	91.1	47.9

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.

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

	For the Year Ended December 31,		
	2010	2009	2008
Natural Gas Pipelines & Services	$ 167.2	$ 148.2	$ 159.0
NGL Pipelines & Services	122.8	103.4	82.9
Petrochemical Services	9.6	10.5	11.1
Total segment gross operating margin	$ 299.6	$ 262.1	$ 253.0

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP net income, see "Other Items – Non-GAAP Reconciliations" 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 indicated (dollars in millions):

	For the Year Ended December 31,		
	2010	2009	2008
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 536.5	$ 460.2	$ 1,100.2
Natural gas transportation services	286.1	263.2	246.7
Natural gas storage services	16.0	15.3	8.4
Total segment revenues	$ 838.6	$ 738.7	$ 1,355.3
NGL Pipelines & Services:			
Sales of NGLs	$ 45.9	$ 35.0	$ 47.9
Sales of other products	18.2	11.3	15.0
NGL and related product storage services	120.5	104.9	87.4
NGL fractionation services	30.8	29.5	32.4
NGL transportation services	45.4	43.8	43.6
Other services	2.1	2.5	2.3
Total segment revenues	$ 262.9	$ 227.0	$ 228.6
Petrochemical Services:			
Propylene transportation services	$ 13.6	$ 13.6	$ 14.2
Total consolidated revenues	$ 1,115.1	$ 979.3	$ 1,598.1

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

Revenues for 2010 were $1.12 billion compared to $979.3 million for 2009, a $135.8 million year-to-year increase. Higher energy commodity prices and sales volumes during 2010 relative to 2009 resulted in a $94.1 million year-to-year increase in consolidated revenues from the sale of natural gas, NGLs and other products. Consolidated revenues from sales of natural gas increased $76.3 million year-to-year, of which approximately half of the increase was attributable to higher prices during 2010 compared to 2009, with the remainder attributed to higher sales volumes in 2010. Revenues from sales of NGLs increased $10.9 million year-to-year primarily due to higher prices in 2010 when compared to 2009. Consolidated revenues from the sale of other products increased $6.9 million year-to-year primarily due to higher sales volumes.

Collectively, consolidated revenues from the provision of services increased $41.7 million year-to-year. Revenues from natural gas transportation and storage services increased $23.6 million year-to-year. A $38.1 million year-to-year increase in firm capacity reservation fees earned by the Sherman Extension of our Texas Intrastate System was partially offset by the effects of lower throughput volumes on other segments of the Texas Intrastate System. The Sherman Extension pipeline began earning capacity reservation fees during August 2009. 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 compared to 2009. The year-to-year decrease in basis differentials resulted in lower pipeline throughput volumes during 2010 on certain segments of the Texas Intrastate System.

Revenues from NGL and related product storage services provided at our Mont Belvieu complex increased $15.6 million year-to-year primarily due to higher storage volumes and fees during 2010 compared to 2009. In general, storage volumes and fees charged to customers have increased year-to-year at our Mont Belvieu storage complex primarily due to higher demand for storage capacity. The remaining $2.5 million year-to-year increase in consolidated revenues is primarily due to higher NGL transportation and fractionation volumes on our South Texas NGL System. The year-to-year increase in volumes on our South Texas NGL System is attributable to an increase in the supply of NGLs from natural gas production in the Eagle Ford Shale.

Operating costs and expenses were $1.03 billion for 2010 compared to $908.3 million for 2009, a $122.1 million year-to-year increase. The cost of sales of our natural gas and NGL products increased $93.9 million year-to-year primarily as a result of higher energy commodity prices and sales volumes. Depreciation, amortization and accretion expense included in operating costs and expenses increased $14.7 million year-to-year primarily due to asset retirement obligations of our TPC Offshore gathering system and an increase in depreciation expense due to our construction of new assets and facility expansions. Operating costs and expenses for 2010 include non-cash asset impairment cha rges of $5.2 million compared to $4.2 million of such charges for 2009. Operating costs and expenses for 2010 also include a $9.1 million non-cash loss for the disposition of a small segment of non-strategic pipeline and $6.8 million of accrued expense related to litigation for a contractual dispute. Consolidated operating costs and expenses also include operational measurement gains and losses at our Mont Belvieu storage complex, which decreased $11.2 million year-to-year. Collectively, the remainder of our consolidated operating costs and expenses increased $7.8 million year-to-year primarily due to higher operating expenses (e.g., maintenance and pipeline integrity costs) at certain of our pipeline and storage facilities during 2010 compared to 2009.

Changes in our revenues and operating costs and expenses year-to-year are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of natural gas and NGLs; however, these higher commodity prices also increase the associated cost of sales as purchase prices rise. 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 weighted-average indicative market price for NGLs was $1.16 per gallon during 2010 versus $0.85 per gallon during 2009. Our determination of the weighted-avera ge 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.

General and administrative costs were $20.0 million for 2010 compared to $11.2 million for 2009, an $8.8 million year-to-year increase. General and administrative costs increased $1.3 million year-to-year due to legal expenses and other professional services primarily related to our Haynesville Extension and Trinity River Lateral projects. The remaining $7.5 million year-to-year increase in general and administrative costs is primarily due to higher employee compensation costs, which includes $2.3 million of expense related to the Employee Partnership liquidations in 2010. Equity in income of Evangeline decreased $0.3 million year-to-year primarily due to lower natural gas sales volumes and margins in 2010 compared to 2009.

Operating income for 2010 was $65.5 million compared to $60.9 million for 2009. Collectively, the changes in revenues, costs and expenses and equity in income of Evangeline described above resulted in the $4.6 million year-to-year increase in operating income.

Interest expense decreased $1.9 million year-to-year primarily due to higher capitalized interest amounts in 2010 compared to 2009 as a result of our increased capital expenditures. Income tax expense for the Texas Margin Tax decreased $1.3 million year-to-year.

As a result of items noted in the previous paragraphs, net income increased $7.6 million year-to-year to $53.4 million for 2010 compared to $45.8 million for 2009.

We account for EPO's share of the net income of the DEP I and DEP II Midstream Businesses as noncontrolling interest, which is an adjustment to net income to arrive at the amount of net income attributable to Duncan Energy Partners L.P. EPO was attributed $27.7 million of the net income of the DEP I Midstream Businesses for 2010 compared to $15.3 million for 2009. The year-to-year increase in EPO's share of the net income of the DEP I Midstream Businesses is primarily due to changes in the amount of operational measurement gains and losses recorded by Mont Belvieu Caverns (EPO is allocated 100% of such gains and losses). In addition, EPO was attributed losses of $64.4 million and $60.6 million in connection with it s ownership interests in the DEP II Midstream Businesses for 2010 and 2009, respectively. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our determination of net income attributable to EPO's noncontrolling interest.

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

Natural Gas Pipelines & Services. Gross operating margin from this business segment was $167.2 million for 2010 compared to $148.2 million for 2009, a $19.0 million year-to-year increase. Total natural gas throughput volumes were 4.69 TBtus/d during 2010 compared to 4.66 TBtus/d during 2009. Gross operating margin from natural gas transportation and storage services provided by our Texas Intrastate System increased $22.5 million year-to-year. A $38.1 million year-to-year increase in firm capacity reservation fee revenues on the Sherman Extension was partially offset by the effects of lower throughput volumes on other segments of the Texas Intrastate System. Collectively, gross operating margin for the remainder of the businesses within this segment decreased $3.5 million year-to-year primarily due to lower natural gas sales margins on our Acadian Gas System.

NGL Pipelines & Services. Gross operating margin from this business segment was $122.8 million for 2010 compared to $103.4 million for 2009, a $19.4 million year-to-year increase. Mont Belvieu Caverns' recorded operational measurement gains of $9.5 million in 2010 compared to operational measurement losses of $1.7 million in 2009. Excluding operational measurement gains and losses, segment gross operating margin increased $8.2 million year-to-year.

Excluding operational measurement gains and losses, gross operating margin from our Mont Belvieu storage complex increased $13.3 million year-to-year primarily due to higher storage volumes and fees during 2010 compared to 2009. During November 2010, we completed the conversion of the first storage cavern at our Mont Belvieu storage complex from NGL service to refined products service. We expect to earn higher storage fees from caverns placed in refined products service. Gross operating margin from our South Texas NGL System increased $0.7 million year-to-year. A year-to-year increase in revenues from our South Texas NGL System due to higher NGL transportation and fractionation volumes was partially offset by the hi gher operating expenses and the effects of scheduled downtime at our Shoup NGL fractionator for maintenance and facility expansion projects during 2010. We expanded capacity at our Shoup NGL fractionator during 2010 in anticipation of an increase in the supply of NGLs from natural gas production in the Eagle Ford Shale. The remainder of segment gross operating margin decreased $5.8 million year-to-year primarily due to a $6.8 million accrued expense related to litigation for a contractual dispute involving our South Texas NGL System.

Petrochemical Services. Gross operating margin from this business segment was $9.6 million for 2010 compared to $10.5 million for 2009, a $0.9 million year-to-year decrease. Petrochemical transportation volumes increased to 35 MBPD during 2010 from 30 MBPD during 2009. The $0.9 million year-to-year decrease in segment gross operating margin is primarily due to higher pipeline integrity expenses on our Lou-Tex Propylene Pipeline, which more than offset the effects of a year-to-year increase in transportation volumes on the Lou-Tex and Sabine Propylene Pipelines.

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

Revenues for 2009 were $979.3 million compared to $1.60 billion for 2008, a $618.8 million year-to-year decrease. Lower energy commodity prices and sales volumes during 2009 relative to 2008 resulted in a $656.6 million year-to-year decrease in revenues from the sale of natural gas, NGLs and other products. Consolidated revenues from the sale of natural gas decreased $640.0 million year-to-year with almost all of the decrease attributable to lower prices during 2009 compared to 2008. Likewise, revenues from the sale of NGLs and other products decreased $16.6 million year-to-year primarily due to lower prices in 2009.

Collectively, consolidated revenues from the provision of services increased $37.8 million year-to-year. Revenues from natural gas transportation and storage services increased $23.4 million year-to-year primarily due to firm capacity reservation fees earned by the Sherman Extension during 2009. The Sherman Extension began earning capacity reservation fees in August 2009. Revenues from our NGL and related product storage services increased $15.0 million year-to-year primarily due to strong demand for storage services at our Mont Belvieu complex, which resulted in a year-to-year increase in storage volumes and fees. Revenues from our propylene transportation services decreased $0.6 million year-to-year primarily due to lower transportation volumes in 2009 relative to 2008.

Operating costs and expenses were $908.3 million for 2009 compared to $1.51 billion for 2008, a $604.5 million year-to-year decrease. The cost of sales of our natural gas and NGL products decreased $644.2 million year-to-year primarily due to lower energy commodity prices and sales volumes. Depreciation, amortization and accretion expense included in operating costs and expenses increased $19.0 million year-to-year primarily due to an increase in depreciation expense resulting from our construction of new assets (e.g., the Sherman Extension pipeline) and facility expansions. Consolidated operating costs and expenses for 2009 include non-cash asset impairment charges of $4.2 million. Operating costs and expenses for 2008 included an aggregate benefit of $13.2 million associated with our Texas Intrastate System related to favorable adjustments for certain audit claims and changes in the anticipated cost to complete an environmental remediation project. Consolidated operating costs and expenses decreased $5.1 million year-to-year attributable to operational measurement gains and losses at our Mont Belvieu storage complex. Collectively, the remainder of our consolidated operating costs and expenses increased $8.4 million year-to-year largely due to higher operating expenses incurred during 2009 for the Sherman Extension as well as an overall increase in employee compensation and asset maintenance costs.

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

General and administrative costs were $11.2 million for 2009 compared to $18.3 million for 2008. The $7.1 million year-to-year decrease in general and administrative costs was primarily due to lower costs associated with the DEP II Midstream Businesses. Equity in income of Evangeline increased $0.2 million year-to-year.

Operating income for 2009 was $60.9 million compared to $67.9 million for 2008. Collectively, the changes in revenues, costs and expenses and equity in income of Evangeline described above resulted in the $7.0 million year-to-year decrease in operating income.

Interest expense increased $2.0 million year-to-year primarily due to borrowings we made in connection with the DEP II drop down transaction in December 2008. Provision for income taxes increased $0.2 million year-to-year primarily due to the Texas Margin Tax.

As a result of items noted in the previous paragraphs, net income decreased $9.5 million year-to-year to $45.8 million for 2009 compared to $55.3 million for 2008.

EPO was attributed $15.3 million of the net income of the DEP I Midstream Businesses for 2009 compared to $11.4 million for 2008. EPO was attributed losses in connection with its ownership interests in the DEP II Midstream Businesses of $60.6 million for 2009 and $4.0 million for the period from December 8, 2008 to December 31, 2008. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our determination of net income attributable to EPO's noncontrolling interest.

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

Natural Gas Pipelines & Services. Gross operating margin from this business segment was $148.2 million for 2009 compared to $159.0 million for 2008, a $10.8 million year-to-year decrease. Total natural gas throughput volumes were 4.66 TBtus/d during 2009 compared to 4.73 TBtus/d during 2008. Gross operating margin from natural gas transportation and storage services provided by our Texas Intrastate System decreased $8.0 million year-to-year. Results for the Texas Intrastate System for 2009 include $24.8 million of firm capacity reservation fee revenues earned by th e Sherman Extension and a $5.4 million year-to-year increase in gross operating margin from the Wilson Storage facility primarily due to higher firm storage reservation fee revenues. Collectively, these benefits were more than offset by an $11.5 million year-to-year decrease in revenues from the sale of pipeline condensate, higher operating expenses and the effects of lower throughput volumes on other segments of the Texas Intrastate System. Collectively, gross operating margin for the remainder of the businesses within this segment decreased $2.8 million year-to-year primarily due to lower natural gas sales volumes and margins on the Acadian Gas System.

NGL Pipelines & Services. Gross operating margin from this business segment was $103.4 million for 2009 compared to $82.9 million for 2008, a $20.5 million year-to-year increase. Mont Belvieu Caverns recorded operational measurement losses of $1.7 million in 2009 compared to $6.8 million in 2008. Excluding operational measurement gains and losses, segment gross operating margin increased $15.4 million year-to-year. Gross operating margin from our Mont Belvieu storage complex increased $17.8 million year-to-year (net of operational measurement gains and losses) primarily due to higher storage volumes and fees during 2009 compared to 2008. Collectively, gross operating margin from the remainder of the businesses within this segment decreased $2.4 million year-to-year primarily due to lower NGL sales margins and NGL transportation and fractionation volumes.

Petrochemical Services. Gross operating margin from this business segment was $10.5 million for 2009 compared to $11.1 million for 2008. Petrochemical transportation volumes decreased to 30 MBPD during 2009 from 35 MBPD during 2008. The $0.6 million year-to-year decrease in segment gross operating margin was primarily due to lower transportation volumes on our Lou-Tex Propylene Pipeline.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures and distributions to owners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and borrowings under our Multi-Year Revolving Credit Facility. 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, cash contributions from EPO and the issuance of additional equity securities. We expect to fund cash distribution s to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2010, we had approximately $763.4 million of liquidity, which includes availability under our Multi-Year Revolving Credit Facility. At December 31, 2010, our total debt balance was $788.3 million, which includes $106.0 million outstanding under our Multi-Year Revolving Credit Facility, the $400 million we borrowed on October 25, 2010 under our $400 Million Term Loan Facility and the $282.3 million we borrowed on December 8, 2008 under our Term Loan Agreement. Our liquidity level at December 31, 2010 was significantly higher than in prior periods as a result of having entered into the Revolving Credit and Term Loan Agreement in October 2010 in order to fund our share of the capital spending requirements of the Haynesville Extension project. Over the course of 2011, we expect our liquidity level to decrease in proportion to increases in b orrowings under our Multi-Year Revolving Credit Facility. We were in compliance with the financial covenants of our loan agreements at December 31, 2010 and 2009.

It is our belief that we will continue to have adequate liquidity and capital resources to fund future recurring operating and investing activities in 2011. For a discussion of our liquidity outlook, see "General Outlook for 2011" within this Item 7.

Registration Statements

We may issue equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that allows us to issue up to $1 billion in equity and debt securities for general partnership purposes. After taking into account previously issued securities under this registration statement, we may issue approximately $856.4 million of additional securities under this registration statement. We did not utilize this registration statement during 2010.

We also have a registration statement on file with the SEC authorizing the issuance of up to 2,000,000 common units in connection with a distribution reinvestment plan ("DRIP"). The DRIP gives unitholders of record and beneficial owners of our common units the ability to increase the number of our common units they own through voluntarily reinvesting their quarterly cash distributions into the purchase of additional common units. Plan participants may purchase our common units at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. We issued 41,29 1 common units in connection with the DRIP for the year ended December 31, 2010, which generated cash proceeds of $1.0 million from plan participants.

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 common units in connection with the EUPP and the 2010 Plan. These plans became effective on February 11, 2010. For the year ended December 31, 2010, we issued 6,348 common units in connection with the 2010 Plan and 24,532 common units in connection with the EUPP. The EUPP generated cash proceeds of $0.7 million from plan participants.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (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 the Year Ended December 31,		
	2010	2009	2008
Net cash flows provided by operating activities	$ 310.4	$ 201.6	$ 220.1
Cash used in investing activities	927.3	428.8	748.8
Cash provided by financing activities	645.4	218.1	539.5

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, refined products and certain petrochemicals. The products that we fractionate, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufa cturing; 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 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 depreci ation, amortization, changes in the fair market value of derivative instruments and equity in income from Evangeline 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.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to and contributions from owners, and proceeds from the issuance of equity securities.

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

Comparison of 2010 with 2009

Operating activities. The $108.8 million increase in net cash flows provided by operating activities was primarily due to the timing of cash receipts and disbursements.

Investing activities. The $498.5 million increase in cash used for investing activities was primarily due to the following:

§ A $591.8 million increase in capital expenditures as a result of expansion projects such as the Haynesville Extension and those of our Texas Intrastate System.

In June 2010, we entered into the Amended Acadian LLC Agreement with EPO. As a part of this agreement, we and EPO agreed to fund the construction spending of the Haynesville Extension in accordance with our respective sharing ratios in Acadian Gas (i.e., 66% for us and 34% for EPO). For additional information regarding the Amended Acadian LLC Agreement, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ A $45.6 million cash inflow in January 2010 attributable to EPO’s repayment of a temporary cash advance made by a subsidiary in December 2009.

Financing activities. The $427.3 million increase in cash provided by financing activities was primarily due to:

§ Net borrowings under bank credit agreements of $331.0 million in 2010 compared to net repayments of $27.0 million in 2009. The increased borrowing is a result of capital spending requirements for our share of the Haynesville Extension project and use of proceeds from our new long-term credit facilities to terminate our Revolving Credit Facility and Loan Agreement with EPO in October 2010. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our new long-term credit facilities and the termination of our Revolving Credit Facility and Loan Agreement with EPO.

§ A $131.6 million increase in contributions from EPO, as noncontrolling interest, related to its funding of all or a portion of expansion capital project costs.

§ A $57.5 million increase in distributions consisting of a $15.4 million increase in distributions to our unitholders and general partner and a $42.1 million increase in distributions to EPO (as noncontrolling interest). Declared distributions are paid in the quarter following their declaration; therefore, the cash amount for 2009 includes distributions related to the fourth quarter of 2008, which reflects a prorated amount of distributions from the DEP II Midstream Businesses for the period December 8, 2008 through December 31, 2008, plus cash distributions pertaining to the first three quarters of 2009. Cash distributions for 2010 reflect a full year of distributions from the DEP II Midstream Businesses.

§ In June 2009, we completed an offering of 8,000,000 common units that generated net cash proceeds of approximately $122.9 million after underwriting discounts and other expenses. In July 2009, the underwriters to this offering exercised their option to purchase an additional 943,400 common units, which generated approximately $14.5 million of additional net cash proceeds. The total net cash proceeds from this offering, including the overallotment amount, were used to repurchase an equal number of our common units beneficially owned by EPO: 8,000,000 units were repurchased in June 2009 and 943,400 units were repurchased in July 2009. The repurchased common units were subsequently cancelled.

Comparison of 2009 with 2008

Operating activities. The $18.5 million decrease in cash flows provided by operating activities was primarily due to the timing of cash receipts and disbursements.

Investing activities. The $320.0 million year-to-year decrease in cash used for investing activities was primarily due to the completion of growth capital projects of the DEP II Midstream Businesses that were under construction during 2008. In February 2009, we completed construction of the Sherman Extension pipeline, which is a component of our Texas Intrastate System. The Sherman Extension Pipeline commenced operations on August 1, 2009.

Financing activities. The $321.4 million year-to-year decrease in cash provided by financing activities was primarily due to:

§ A $311.2 million decrease in net borrowings under our credit agreements. Borrowings for 2008 include the $282.3 million we borrowed under the Term Loan Agreement to fund the $280.5 million cash consideration paid to EPO in connection with the DEP II drop down transaction in December 2008. Cash distributions paid to EPO as noncontrolling interest decreased $266.5 million year-to-year primarily due to the $280.5 million payment made to EPO in connection with the DEP II drop down.

§ A $54.5 million increase in distributions to our unitholders and general partner attributable to an increase in the number of our common units outstanding and the quarterly cash distribution rates.

§ A $222.9 million decrease in contributions from EPO (as both former owner of the DEP II Midstream Businesses prior to December 8, 2008 and as noncontrolling interest owner in the DEP I Midstream Businesses and the DEP II Midstream Businesses (post-December 8, 2008)). The decrease in contributions is generally due to the lower level of capital expenditures we made during 2009 compared to 2008.

Capital Expenditures

Part of our business strategy involves expansion through growth capital projects and business combinations. The following table summarizes our capital spending by activity for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2010	2009	2008
DEP I Midstream Businesses:			
Expansion capital spending (1)	$ 613.8	$ 28.5	$ 127.7
Sustaining capital expenditures (2)	18.9	13.9	12.8
DEP II Midstream Businesses:			
Expansion capital spending (1)	309.3	311.0	576.5
Sustaining capital expenditures (2)	43.1	35.7	42.5
Total capital spending	$ 985.1	$ 389.1	$ 759.5

(1) EPO funded 100% of expansion capital spending for 2009 and 2008. In 2010, we elected to participate in the Haynesville Extension project with EPO in accordance with our respective ownership interests in Acadian Gas. We have also elected to participate in a Mont Belvieu Caverns project that consists of converting two storage caverns from NGL to refined products service, one of which was completed in November 2010.

(2) Sustaining capital expenditures are capital expenditures (as defined by U.S. GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

The majority of our capital spending during 2010 was attributable to the Haynesville Extension project and expansions of the Texas Intrastate System, including Eagle Ford Shale projects and the Trinity River Lateral pipeline.

Based on information currently available, we estimate our consolidated capital spending for property, plant and equipment for 2011 will approximate $1.73 billion, which includes estimated expenditures of approximately $1.67 billion for growth capital projects (including $930 million for the Haynesville Extension and $713 million for Eagle Ford Shale projects) and approximately $57 million for sustaining capital expenditures. Duncan Energy Partners expects to fund approximately $625 million of the 2011 growth capital project spending and $15 million of 2011 sustaining capital expenditures.   EPO will fund the remaining expenditures.

Our forecast of capital expenditures is based on our currently announced growth plans. 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.

Excluding the Haynesville Extension, EPO (as Parent) funds the majority of our growth capital spending under agreements executed in connection with the DEP I and DEP II drop down transactions. See Notes 13 and 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our relationship with EPO and its funding of our growth capital spending.

In order to fund our share of growth capital spending, we depend on our ability to generate the required funds from either operating cash flows or from other means, including borrowings under our debt agreements and/or the issuance of equity. 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 $285.3 million in purchase commitments outstanding that relate to our spending for property, plant and equipment. These commitments primarily relate to our Haynesville Extension project and Eagle Ford Shale projects.

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 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 indicated (dollars in millions):

	For the Year Ended December 31,		
	2010	**2009**	**2008**
Expensed	$ 14.3	$ 14.1	$ 20.6
Capitalized	10.3	17.0	22.9
Total	$ 24.6	$ 31.1	$ 43.5

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $27.5 million for 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.

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 the assets. Our estimate of depreciation 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 woul d 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 $5.36 billion and $4.55 billion, respectively. We recorded $187.3 million, $176.7 million and $158.5 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, crude oil or NGLs. Long-lived assets with recorded 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 the 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 as signed 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.

During 2010 and 2009, we recognized non-cash asset impairment charges related to property, plant and equipment of $5.2 million and $4.2 million, respectively, which are reflected as a component of operating costs and expenses. No such non-cash asset impairment charges were recorded in 2008. We did not recognize any impairment charges related to our equity method investment in Evangeline during the three years ended December 31, 2010.

For additional information regarding impairment charges associated with our long-lived assets, see Note 6 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, 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 the customer bases we acquired in connection with the DEP II drop down. These customer relationships were acquired by Enterprise in connection with a merger transaction it completed in 2004 and a business combination it completed in 2007. We amortize the value of our customer relationships to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying NGL 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 product ion and exploration activities.

We acquired contract-based intangible assets in connection with the DEP I and DEP II drop down transactions. Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements. 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 $38.0 million and $43.8 million, respectively. We recorded $8.2 million, $8.5 million and $9.1 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 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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 assets classified within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;

§ 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. The carrying value of our goodwill was $4.9 million at both December 31, 2010 and 2009. Our goodwill represents an allocation to the DEP II Midstream Businesses of the goodwill recorded by Enterprise in connection with a merger transaction it completed in 2004. We did not record any goodwill impairment charges during the three years ended December 31, 2010.

For additional information regarding our goodwill, see Notes 2 and 10 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. 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 str ict 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 $1.0 million and $0.5 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 17 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 volumes 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 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 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	$ 11.5	$ 9.8
Natural gas imbalance payables (1)	10.6	11.0

(1) Reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets included in Item 8 of this annual report.

Other Items

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 18 of the Notes Consolidated Financial Statements included under Item 8 of this annual report.

Contractual Obligations

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

Contractual Obligations (1)	Payment or Settlement due by Period Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Scheduled maturities of debt obligations (2)	$ 788.3	$ 282.3	$ 506.0	$ --	$ --
Estimated cash interest payments (3)	$ 34.6	$ 14.1	$ 20.5	$ --	$ --
Operating lease obligations (4)	$ 107.2	$ 8.9	$ 16.1	$ 12.9	$ 69.3
Purchase obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas (5)	$ 294.9	$ 172.5	$ 122.4	$ --	$ --
Other	$ *	$ *	$ *	$ --	$ --
Underlying major volume commitments:					
Natural gas (in BBtus)	69,959	40,926	29,033	--	--
Capital expenditure commitments (6)	$ 285.3	$ 285.3	$ --	$ --	$ --
Other long-term liabilities (7)	$ 13.4	$ --	$ 0.3	$ 0.2	$ 12.9
Total	$ 1,523.7	$ 763.1	$ 665.3	$ 13.1	$ 82.2

* Amounts are negligible.

(1) The contractual obligations presented in this table reflect 100% of our subsidiaries' obligations even though we own less than a 100% equity interest in our operating subsidiaries.

(2) Represents our scheduled future maturities of consolidated debt principal obligations for the periods indicated. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our debt obligations.

(3) Our estimated cash payments for interest are based on the principal amount of consolidated debt obligations outstanding at December 31, 2010. In calculating these amounts, we applied the weighted-average variable interest rates paid during 2010 associated with such debt. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for the weighted-average variable interest rates charged during 2010 under our credit agreements.

(4) Primarily represents operating leases for underground caverns for the storage of natural gas and NGLs and land held pursuant to right-of-way agreements. See Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our operating leases.

(5) Represents enforceable and legally binding natural gas purchase commitments of Acadian Gas. See Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our purchase obligations. 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.

(6) Represents short-term unconditional payment obligations related to our capital projects (on a 100% basis). With respect to the amount presented, we expect reimbursements of $113.4 million from EPO.

(7) As reflected on our Consolidated Balance Sheet at December 31, 2010, other long-term liabilities primarily represent noncurrent portions of asset retirement obligations. For information regarding our asset retirement obligations, see Note 8 of our Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Off-Balance Sheet Arrangements

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.

We have no other off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have had or are reasonably expected to have a material current or future effect on our financial position, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

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.

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 indicated (dollars in millions):

	For the Year Ended December 31,		
	2010	**2009**	**2008**
Total segment gross operating margin	$ 299.6	$ 262.1	$ 253.0
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses (1)	(201.0)	(186.3)	(167.3)
Non-cash asset impairment charges included in operating costs and expenses (2)	(5.2)	(4.2)	--
Gain (loss) from asset sales and related transactions in operating costs and expenses (3)	(7.9)	0.5	0.5
General and administrative costs	(20.0)	(11.2)	(18.3)
Operating income	65.5	60.9	67.9
Other expense, net	(12.1)	(13.8)	(11.5)
Income before provision for income taxes	$ 53.4	$ 47.1	$ 56.4

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on the Statements of Consolidated Cash Flows.
(2) See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding non-cash asset impairment charges.
(3) Amount presented for the twelve months ended December 31, 2010 includes a $9.1 million loss related to the disposal of a non-strategic pipeline segment owned by Enterprise Texas.

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 expense; (ii) non-cash asset impairment charges; (iii) gains and losses from asset sales and related transactions; and (iv) 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 any intersegment and intrasegment 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.

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 and commodity prices. 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. Typical derivative instruments include physical forward agreements, futures contracts, floating-to-fixed swaps, basis swaps and options contracts. 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 deriva tive instruments and hedging activities.

Interest Rate Derivative Instruments

We utilized interest rate swaps to manage our exposure to changes in the interest rates charged on borrowings under our Revolving Credit Facility from September 2007 through September 2010. This strategy was a component in controlling our cost of capital associated with such borrowings. Our interest rate swaps expired in September 2010.

Commodity Derivative Instruments

The price of natural gas fluctuates 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-based derivative instruments such as futures, swaps and forward contracts to mitigate such risks.

We assess the risk of our commodity financial 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 market prices of the commodity derivative instruments outstanding at the date indicated within the following tables.

The following table presents the effect of hypothetical price movements on the estimated fair value of this portfolio at the dates presented (dollars in millions).

		Portfolio FV at		
Scenario	**Resulting Classification**	**December 31, 2009**	**December 31, 2010**	**January 31, 2011**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ *	$ *	$ *
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	*	*	*
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	*	*	*

* Amounts are negligible

Product Purchase Commitments

We have long- and short-term purchase commitments for natural gas. 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 that 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.

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

The management of Duncan Energy 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 Duncan Energy 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 Duncan Energy 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, Duncan Energy 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 Duncan Energy 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 Duncan Energy 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/ W. Randall Fowler
Name: W. Randall Fowler
Title: Chief Executive Officer of our general partner, DEP Holdings, LLC

/s/ Bryan Bulawa
Name: Bryan Bulawa
Title: Chief Financial Officer of our general partner, DEP Holdings, LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of DEP Holdings, LLC and
Unitholders of Duncan Energy Partners L.P.
Houston, Texas

We have audited the internal control over financial reporting of Duncan Energy 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 c ontrol 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) provid e 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.

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 indicating the financial statements of the Company were prepared from the separate records maintained by Enterprise Products Partners L.P. or affiliates and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity.

/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 and executive officers of our general partner. For additional information regarding the ASA, see “Relationship with EPCO” in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The executive officers of DEP GP, 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 DEP GP. Although the members of our Board are elected by EPO, the DD LLC Trustees, through their indirect control of EPO and our general partner, have the ability to elect, remove and replace at any time, all of the officers and directors of DEP GP. Each member of the Board of our general partner serves until such member’s death, resignation or removal. Mr. Fowler was the only employee of EPCO who served as a director of DEP GP for all of 2010. Messrs. Bachmann, Creel, Cunningham and Teague served as directors of DEP GP from January 1, 2010 until May 21, 2010. M r. Bulawa was elected a director of DEP GP in February 2011.

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 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 maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, DEP 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 DEP GP. Whenever possible, DEP 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 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 us or our general partner (either directly or as a partner, unitholder or officer of an organization that has a material relationship with us or our general partner). Based on the foregoing, the Board has affirmatively determined that William A. Bruckmann, III, Larry J. Casey and Richard S. Snell are “independent” directors under the NYSE rules.

Code of Conduct and Ethics and Corporate Governance Guidelines

DEP 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 chief executive officer, chief financial officer, 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, ac curate, 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 committee charters, provide the framework for effective governance. The Board has adopted the “Governance Guidelines of Duncan Energy Partners,” which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of the Audit, Conflicts and Governance (“ACG”) Committee, the conduct and frequency of board and committee meetings, management succession, 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, the Board will review the Governance Guidelines of Duncan Energy Partners annually or more often as deemed necessary.

We provide access through our website at www.deplp.com to current information relating to governance, including the Code of Conduct, the Governance Guidelines of Duncan Energy Partners and other matters impacting our governance principles. 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.

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. Bruckmann, Casey and Snell. Mr. Joe D. Havens, who resigned from the Board effective as of February 11, 2011, previously served as an additional fourth member of the ACG Committee until the time of his resignation. The Board has affirmatively determined that Mr. Bruckmann 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:

§ review potential conflicts of interest, 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 DEP 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 DEP 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.deplp.com. You may also contact our Investor Relations department at (866) 230-0745 for a printed copy of this document free of charge.

NYSE Corporate Governance Listing Standards

On March 23, 2010, Richard H. Bachmann, our then Chief Executive Officer, 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. On April

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23, 2010, Mr. Bachmann resigned as our CEO. W. Randall Fowler was subsequently elected to serve as our Chief Executive Officer.

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. Bruckmann.

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 DEP GP

The following table sets forth the name, age and position of each of the directors and executive officers of our general partner at March 1, 2011.

Name	Age	Position with DEP GP
W. Randall Fowler (1)	54	Director, President and Chief Executive Officer
William A. Bruckmann, III (2,3)	59	Director
Larry J. Casey (2)	78	Director
Richard S. Snell (2)	68	Director
Bryan F. Bulawa (1)	41	Director, Senior Vice President, Treasurer and Chief Financial Officer
A. James Teague (1)	65	Executive Vice President and Chief Commercial Officer
William Ordemann (1)	51	Executive Vice President
Stephanie C. Hildebrandt (1)	46	Senior Vice President, Chief Legal Officer and Secretary
Michael J. Knesek (1)	56	Senior Vice President, Controller and Principal Accounting Officer

(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 the directors and executive officers of DEP GP serving as of March 1, 2011.

W. Randall Fowler. Mr. Fowler was 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 and as Senior Vice President and Treasurer of DEP GP from October 2006 to August 2007. He has also served as a Director of DEP GP since September 2006. Mr. Fowler has also served as Executive Vice President and CFO of Enterprise GP since August 2007. He previously served as Executive Vice President and CFO of EPGP from August 2007 to November 2010 and as a Director of EPGP from February 2006 to May 2010. Mr. Fowler served as Senior Vice President and Treasure r of EPGP from February 2005 to August 2007. 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 of EPCO 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.

William A. Bruckmann, III. Mr. Bruckmann was elected a Director of DEP GP in October 2006. Mr. Bruckmann has been self-employed as a consultant and private investor since April 2004. From

September 2002 to April 2004, Mr. Bruckmann served as a financial advisor with UBS Securities, Inc. He is a former Managing Director at Chase Securities, Inc. and has more than 25 years of banking experience, starting with Manufacturers Hanover Trust Company, where he became a senior officer in 1985. Mr. Bruckmann later served as Managing Director, sector head of Manufacturers Hanover's gas pipeline and midstream energy practices through the acquisition of Manufacturers Hanover by Chemical Bank and the acquisition of Chemical Bank by Chase Bank. Mr. Bruckmann also served as a Director of Williams Energy Partners L.P. from May 2001 to June 2003. Mr. Bruckmann serves on our ACG Committee as its Chairman.

Larry J. Casey. Mr. Casey was elected a Director of DEP GP in October 2006. Mr. Casey has been a private investor managing real estate and personal investments since he retired in 1982 from a career in the energy industry. In 1974, Mr. Casey founded Xcel Products Company, an NGL and petrochemical trading company. Also in 1974, he founded Xral Underground Storage, the first privately owned underground merchant storage facility for NGLs and specialty chemicals at Mont Belvieu, Texas. Mr. Casey sold these companies in 1982. Mr. Casey serves on our ACG Committee.

Richard S. Snell. Mr. Snell, a Certified Public Accountant, was elected a Director of DEP GP in January 2010. Mr. Snell most recently served as a director of TEPPCO GP from January 2006 until TEPPCO's merger with a subsidiary of Enterprise in October 2009. From June 2000 until February 2006, he served as a director of EPGP. He has been a partner with the law firm of Thompson & Knight LLP since May 2000. Prior to his position with Thompson & Knight LLP, he worked as an attorney for the Snell & Smith, P.C. law firm from its founding in 1993 until May 2000. Mr. Snell serves on our ACG Committee.

Bryan F. Bulawa. Mr. Bulawa was elected a Director of DEP GP in February 2011 and as Senior Vice President, CFO and Treasurer of DEP GP in April 2010, having previously served as Senior Vice President and Treasurer of DEP GP from October 2009 to April 2010. He was elected Senior Vice President and Treasurer of Enterprise GP and EPGP in October 2009, having served as Vice President and Treasurer of EPGP from July 2007 to October 2009. Mr. Bulawa 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 served as director of the firm's U. S. Energy Corporate Finance and Distribution group.

A. James Teague. Mr. Teague was elected Executive Vice President and Chief Commercial Officer of DEP GP and EPGP in July 2008. He previously served as a Director of DEP GP from July 2008 to May 2010. Mr. Teague was elected Executive Vice President and 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 previously served as a Director of Enterprise GP from October 2009 to May 2010. Mr. Teague joined Enterprise in connection with the 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.

William Ordemann. Mr. Ordemann was elected an Executive Vice President of DEP GP in August 2007. He was elected 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. Mr. Ordemann 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. Prior to joining Enterprise, Mr. Ordemann held senior management positions at Shell Midstream Enterprises, LLC and Tejas Natural Gas Liquids, LLC, both o f which were affiliates of Shell Oil Company.

Stephanie C. Hildebrandt. Ms. Hildebrandt has served as Senior Vice President, Chief Legal Officer and Secretary of DEP GP since April 2010. Ms. Hildebrandt was elected as Senior Vice President and 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. She previously served as Vice President and General Counsel of EPGP since October 2009, as Vice President and Deputy General Counsel of EPGP from 2006 to 2009, and as Deputy General Counsel of EPGP from 2004 to 2006. Prior to joining the Partnership, Ms. Hildebrandt practiced law for three years at El Paso Corporation and for 12 years at Texaco Inc.

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

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.

Mr. Fowler and Mr. Bulawa are the only directors who are employees of EPCO and also officers of our general partner or its affiliates. Mr. Fowler has significant experience in our industry as an executive officer as well as other qualifications, attributes and skills. His qualifications include over ten years of experience with our midstream assets, including finance, accounting (inactive certified public accountant) and investor public relations and, for over the last six years, as a member of Enterprise's executive management team. Mr. Fowler has worked in accounting and finance positions in the energy industry since 1979. Mr. Bulawa has over three years of management experience in our partnership's treasury and finance activities and over 16 years of finance experience with a focus on the energy industry.

Our three 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. Casey, executive management of NGL and petrochemicals trading, and related storage businesses; for Mr. Bruckmann, investment banking, including financial advisory, commercial banking, and working with complex financial statements; and for Mr. Snell, legal, review of accounting and financial statements and director oversight functions for other midstream assets of our affiliates.

Section 16(a) Beneficial Ownership Reporting Compliance

Under the federal securities laws, DEP GP, directors and executive officers of DEP GP 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 that ownership 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 by these dates during 2010. All such reporting was done in a timely manner in 2010, except that Mr. Joe D. Havens (who served as a director until his resignation effective as of February 11, 2011) filed three late Form 4s reporting purchase transactions that he inadvertently failed to timely report by their respective reporting deadlines. The first For m 4 was filed on February 11, 2010, in which Mr. Havens reported one purchase transaction (executed on February 8, 2010) that he inadvertently failed to report by the reporting deadline on February 10, 2010. The second Form 4 was filed on May 20, 2010, in which Mr. Havens reported one purchase transaction (executed on May 10, 2010) that he inadvertently failed to report by the reporting deadline on May 12, 2010. The third Form 4 was filed on May 28, 2010, in which Mr. Havens reported seven purchase transactions (executed on February 7, 2008; May 8, 2008; August 8, 2008; November 13, 2008; February 10, 2009; May 11, 2009 and August 10, 2009) that he inadvertently failed to report by the applicable reporting deadline for each such transaction.

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.

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 each person who served as the CEO, each person who served as 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.

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Comp. ($) (4)	Total ($)
W. Randall Fowler (5)	2010	$ 65,625	$ 62,500	$ 164,577	$ 17,409	$ 39,641	$ 349,752
(President and CEO;	2009	55,781	95,625	262,684	65,416	21,660	501,166
former Executive Vice President and CFO)	2008	63,594	43,750	459,152	17,850	20,882	605,228
Richard H. Bachmann (6)	2010	24,188	24,375	256,547	26,113	15,809	347,032
(former President and CEO)	2009	129,000	190,000	550,867	133,080	47,295	1,050,242
	2008	159,688	106,250	972,925	35,700	59,055	1,333,618
Bryan F. Bulawa	2010	29,888	16,500	22,589	2,901	9,974	81,852
(Senior Vice President and CFO)							
A. James Teague	2010	162,500	162,500	427,578	43,522	93,111	889,211
(Executive Vice President and	2009	162,500	237,500	611,396	166,350	58,437	1,236,183
Chief Commercial Officer)							
William Ordemann	2010	81,260	50,000	218,145	34,817	56,635	440,857
(Executive Vice President)	2009	63,232	49,600	262,919	90,552	35,275	501,578
	2008	15,656	10,600	71,192	5,712	6,314	109,474
Michael J. Knesek	2010	52,075	30,063	60,506	13,057	21,744	177,445
(Senior Vice President, Controller	2009	50,700	27,625	158,996	54,064	17,099	308,484
and Principal Accounting Officer)	2008	61,800	26,000	185,478	14,280	21,200	308,758

(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 Enterprise's 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. Fowler was elected President and CEO of our general partner on April 23, 2010. Prior to this election, Mr. Fowler served as our Executive Vice President and CFO.

(6) Mr. Bachmann served as President and CEO of our general partner until April 23, 2010. Mr. Bachmann currently serves as President and CEO of EPCO and one of the three EPCO Trustees.

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.

The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses and those of our other affiliates for each of the years presented.

Named Executive Officer	Year	Duncan Energy Partners	EPCO and other affiliates	Total Time Allocated
W. Randall Fowler (CEO)	2010	13%	87%	100%
	2009	11%	89%	100%
	2008	12%	88%	100%
Richard H. Bachmann	2010	4%	96%	100%
(former CEO)	2009	20%	80%	100%
	2008	25%	75%	100%
Bryan F. Bulawa (CFO)	2010	10%	90%	100%
A. James Teague	2010	25%	75%	100%
	2009	25%	75%	100%
William Ordemann	2010	20%	80%	100%
	2009	16%	84%	100%
	2008	4%	96%	100%
Michael J. Knesek	2010	16%	84%	100%
	2009	16%	84%	100%
	2008	20%	80%	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. Enterprise controls our general partner. As discussed further below, Michael A. Creel (the CEO of Enterprise's general partner and a Vice Chairman of EPCO) was given ultimate decision-making authority with respect to 2010 compensation to be paid to our named executive officers, including our CEO. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by the Boar d or the ACG Committee of our general partner. 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. 0; 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.

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 Mr. Creel and EPCO 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. Mr. Creel considers the preliminary recommendation of EPCO's senior vice president of Human Resources and makes revisions, if appropriate. Mr. Creel then makes a final determination regarding compensation of each named executive officer.

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 aw are 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 Mr. Creel has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

Mr. Creel 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, Mr. Creel 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 Mr. Creel and EPCO 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. Mr. Creel and EPCO also consider individual performance, levels of respo nsibility and value to the organization. All compensation determinations are discretionary and, as noted above, subject to the ultimate decision-making authority of Mr. Creel, 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, between Mr. Creel and the senior vice president of Human Resources for EPCO, subject to final determination by Mr. Creel. 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 between Mr. Creel 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 f or additional information.

In the fourth quarter of 2010, EPCO entered into retention agreements with Messrs. 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 EPCO and us will have the services of the executives in the foreseeable future. Pursuant to the retention agreements, Messrs. Fowler, Teague and Ordemann will be entitled to a cash retention payment of $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"). ▯60;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. 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 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. 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, Enterprise 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.

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 and pertain to limited partner interests of Enterprise. 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.

		Estimated Future Payouts Under Equity Incentive Plan Awards				
Name	**Grant Date**	**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)						
W. Randall Fowler (CEO)	2/23/10	--	51,000	--	--	$ 164,577
Richard H. Bachmann (former CEO)	2/23/10	--	53,000	--	--	256,547
Bryan F. Bulawa (CFO)	2/23/10	--	14,000	--	--	22,589
A. James Teague	2/23/10	--	53,000	--	--	427,578
William Ordemann	2/23/10	--	33,800	--	--	218,145
Michael J. Knesek	2/23/10	--	12,500	--	--	60,506
Unit option awards: (2)						
W. Randall Fowler (CEO)	2/23/10	--	60,000	--	$ 32.27	17,409
Richard H. Bachmann (former CEO)	2/23/10	--	60,000	--	32.27	26,113
Bryan F. Bulawa (CFO)	2/23/10	--	20,000	--	32.27	2,901
A. James Teague	2/23/10	--	60,000	--	32.27	43,522
William Ordemann	2/23/10	--	60,000	--	32.27	34,817
Michael J. Knesek	2/23/10	--	30,000	--	32.27	13,057

(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 (with the exception of awards granted to Mr. Bachmann who no longer dedicates any of his time to our affairs) 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.

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 e xpense 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.

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:							
W. Randall Fowler (CEO)	Various (1)	--	--	--	--	130,100	$ 5,413,461
Richard H. Bachmann (former CEO)	Various (1)	--	--	--	--	145,000	6,033,450
Bryan F. Bulawa	Various (1)	--	--	--	--	33,750	1,404,338
A. James Teague	Various (1)	--	--	--	--	145,000	6,033,450
William Ordemann	Various (1)	--	--	--	--	112,700	4,689,447
Michael J. Knesek	Various (1)	--	--	--	--	41,600	1,730,976
Unit option awards:							
W. Randall Fowler (CEO):							
May 29, 2007 option grant	5/29/11	--	45,000	$ 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	--	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	--	--
Richard H. Bachmann (former CEO):							
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	--	--
Bryan F. Bulawa:							
February 23, 2010 option grant	2/23/14	--	20,000	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	--	--
Michael J. Knesek:							
May 29, 2007 option grant	5/29/11	--	30,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	30,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	30,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	30,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	30,000	32.27	12/31/15	--	--

(1) Of the 608,150 restricted common unit awards presented in the table, 103,800 vest in 2011, 127,500 vest in 2012, 159,550 vest in 2013 and 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 Enterprise common units at December 31, 2010 of $41.61 per unit.

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.

	Option Awards		Unit Awards	
Name	**Number of Units Acquired on Exercise (#)**	**Gross Value Realized on Exercise ($)** (1)	**Number of Units Acquired on Vesting (#)**	**Gross Value Realized on Vesting ($)** (2,3)
W. Randall Fowler (CEO):				
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
Richard H. Bachmann (former CEO):				
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			212,097	10,774,622
Bryan F. Bulawa (CFO):				
Employee Partnerships: (3)				
Common units of Enterprise			1,771	66,749
Units of Holdings			3,772	191,619
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
Michael J. Knesek:				
Option awards	45,000	547,950		
Restricted common unit awards			7,200	256,392
Employee Partnerships: (3)				
Common units of Enterprise			8,853	333,668
Units of Holdings			85,253	4,330,891

(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 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.

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 Mr. Creel and EPCO.

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: William A. Bruckmann, III
Larry J. Casey
Richard S. Snell
W. Randall Fowler
Bryan F. Bulawa

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the 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 Mr. Creel and EPCO.

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 during the year ended December 31, 2010.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($) (2)	Total ($)
William A. Bruckmann, III (1)	$ 133,500	$ 40,000	$ 819,000	$ 992,500
Larry J. Casey	118,500	40,000	819,000	977,500
Joe D. Havens (3)	115,500	40,000	819,000	974,500
Richard S. Snell	118,500	40,000	--	158,500

(1) Mr. Bruckmann serves as chairman of our ACG Committee.
(2) Amounts pertain to the settlement of unit appreciation rights in November 2010.
(3) Mr. Havens resigned as a director effective as of February 11, 2011.

For the year ended December 31, 2010, the compensation of our independent directors was 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;

- § Each independent director received an annual grant of our common units having a fair market value, based on the closing price of our common units on the trading day immediately preceding the date of grant, of $40,000.

In February 2007, Messrs. Bruckmann, Casey and Havens were granted a total of 90,000 unit appreciation rights based on the limited partner units of Holdings. These liability awards were in the form of letter agreements and were not part of any established long-term incentive plan of EPCO, Holdings, Enterprise or us. In connection with the merger of Holdings with a wholly-owned subsidiary of Enterprise in November 2010, the letter agreements were cancelled and each of Messrs. Bruckmann, Casey and Havens received a one-time payment of $819,000. The expense associated with these settlements was recognized by our general partner. With the exception of these one-time payments, our independent directors will be compensated in the manner described abo ve in 2011.

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 our common units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Randa Duncan Williams	34,425,140 (1)	59.6%
	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 Enterprise 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 our general partner and indirectly owns 58.5% of our common units through a subsidiary. EPO also retains varying ownership interests in the DEP I and DEP II Midstream Businesses.

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.

	Duncan Energy Partners L.P. Common Units		Enterprise Products Partners L.P. Common Units	
Name of Beneficial Owner	**Amount and Nature Of Beneficial Ownership**	**Percent of Class**	**Amount and Nature Of Beneficial Ownership**	**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%
W. Randall Fowler (CEO) (4)	2,000	*	517,513	*
Richard H. Bachmann (4)	19,486	*	700,933	*
Bryan F. Bulawa (CFO) (4)	2,200	*	42,728	*
A. James Teague (4,5)	6,000	*	689,069	*
William Ordemann (4)	3,810	*	354,891	*
Michael J. Knesek (4,6)	2,340	*	213,422	*
Larry J. Casey	14,050	*	6,600	*
William A. Bruckmann, III	9,764	*	5,782	*
Richard S. Snell	2,685	*	4,077	*
All current directors and executive officers of our general partner (including all named executive officers), as a group (10 individuals in total) (7)	34,487,475	59.7%	336,297,497	39.9%

** 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's common units presented for Mr. Knesek includes 3,245 common units held by a family member for which he has disclaimed beneficial ownership.

(7) Excludes 74,659 Duncan Energy Partners common units and 422,761 Enterprise common units beneficially owned by Joe D. Havens, who resigned as a director effective February 11, 2011.

Ms. Williams also beneficially owns 4,520,431 Class B units of Enterprise, representing 100% of such class of securities.

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.

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 Enterprise owned by an executive officer of our general partner who is also an executive officer of the general partner of Enterprise, 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	Weighted-Average Exercise Price of Outstanding Common Unit Options	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan")	--	--	493,652
Equity compensation plans not approved by unitholders:			
None	--	--	--
Total for equity compensation plans	--	--	493,652

The 2010 Plan, which became effective February 11, 2010, provides for awards of options to purchase common units, restricted common units, unit appreciation rights, phantom units and distribution equivalent rights to employees, directors or consultants providing services to us. Up to 500,000 of our common units may be issued as awards under the 2010 Plan. A total of 6,348 restricted common unit awards were issued under the 2010 Plan to the independent directors of our general partner during the year ended December 31, 2010.

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 four directors: William A Bruckmann, Larry J. Casey, Joe D. Havens and Richard S. Snell. Mr. Havens resigned as a director and as an ACG Committee member effective as of February 11, 2011. After giving effect to Mr. Havens' resignation, the ACG Committee is currently comprised of three directors: Messrs. Bruckmann, Casey and Snell.

During the year ended December 31, 2010, the ACG Committee reviewed and approved (i) the Amended Acadian LLC Agreement and related agreements and transactions and (ii) the Loan Agreement with EPO. For additional information regarding these related party agreements and associated transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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 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 and Duncan Energy Partners and their 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 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 affirmatively 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, unless otherwise expressly provided therein or in the limited liability company ("LLC") agreement of EPO, 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, the LLC agreement of EPO or any agreement contemplated by such agreements, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the respective agreements i s 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, act ion 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 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.

On February 22, 2011, Enterprise submitted a proposal to our ACG Committee to purchase all of our outstanding publicly-held common units through a unit-for-unit exchange. Our ACG Committee has started its review process. See “Significant Recent Developments” under Item 1 and 2 of this annual report for additional information regarding Enterprise’s proposed offer.

Director Independence

Messrs. Bruckmann, Casey and Snell 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 The Year Ended December 31,	
	2010	2009
Audit Fees (1)	$ 0.7	$ 0.9
Audit-Related Fees (2)	N/A	N/A
Tax Fees (3)	N/A	N/A
All Other Fees (4)	N/A	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 last two years.
(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 last two years.

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 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*
3.1	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.2	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 February 5, 2007).
3.3	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 January 3, 2008).
3.4	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 November 10, 2008).
3.5	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 December 8, 2008).
3.6	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 to Form 8-K filed June 15, 2009).
3.7	Certificate of Formation of DEP Holdings, LLC (incorporated by reference to Exhibit 3.3 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.8	Second Amended and Restated Limited Liability Company Agreement of DEP Holdings, LLC, dated May 3, 2007 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed May 4, 2007).
3.9	First Amendment to the Second Amended and Restated Limited Liability Company Agreement of DEP Holdings, LLC dated November 6, 2008 (incorporated by reference to Exhibit 3.8 to Form 10-Q filed November 10, 2008).

3.10	Certificate of Formation of DEP OLPGP, LLC (incorporated by reference to Exhibit 3.5 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.11	Amended and Restated Limited Liability Company Agreement of DEP OLPGP, LLC, dated January 19, 2007 (incorporated by reference to Exhibit 3.6 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-138371) filed January 22, 2007).
3.12	Certificate of Limited Partnership of DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 3.7 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.13	Agreement of Limited Partnership of DEP Operating Partnership, L.P., dated September 29, 2006 (incorporated by reference to Exhibit 3.8 to Amendment No. 1 to Form S-1 Registration Statement (Reg. No. 333-138371) filed December 15, 2006).
10.1***	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 by Enterprise Products Partners L.P. on February 26, 2010).
10.2***	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 filed by Enterprise Products Partners L.P. (Commission File No. 333-150680) on May 6, 2008).
10.3***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.4***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.5***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.6***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.7***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.8***	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 by Enterprise Products Partners L.P. on February 26, 2010).
10.9***	Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit10.1 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.10***	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 by Enterprise Products Partners L.P. on November 9, 2007).
10.11***	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 by Enterprise Products Partners L.P. on May 12, 2008).
10.12***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.13***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued after February 23, 2010 and before August 5, 2010 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).

10.14***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.15***	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 by Enterprise Products Partners L.P. on November 9, 2007).
10.16***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.17***	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 by Enterprise Products Partners L.P. on August 9, 2010).
10.18***	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 by Enterprise Products Partners L.P. on February 26, 2010).
10.19***	2010 Duncan Energy Partners L.P. 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).
10.20***	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 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 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 February 26, 2010).
10.23***	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 by Enterprise Products Partners L.P. on February 26, 2008).
10.24***	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).
10.25***	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 by Enterprise Products Partners L.P. on November 18, 2008).
10.26***	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).
10.27***	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).
10.28***	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 August 8, 2007).
10.29***	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).
10.30***	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).
10.31***	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 by Enterprise Products Partners L.P. on February 28, 2007).
10.32***	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 August 8, 2007).

10.33***	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).
10.34***	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).
10.35***	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).
10.36***	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 August 8, 2007).
10.37***	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).
10.38***	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).
10.39	Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC dated November 1, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed November 10, 2008).
10.40	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 December 8, 2008).
10.41	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 December 8, 2008).
10.42	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 December 8, 2008).
10.43	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 June 3, 2010).
10.44	Amended and Restated Omnibus Agreement dated 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, LLC, Enterprise Texas Pipeline LLC, Enterprise Intrastate L.P. and Enterprise GC, LP (incorporated by reference to Exhibit 10.6 of Form 8-K filed December 8, 2008).
10.45	Fifth Amended and Restated Administrative Services Agreement dated January 30, 2009 by and among EPCO, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., 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 by Enterprise Products Partners L.P. on February 5, 2009).
10.46	Common Unit Purchase Agreement, dated June 15, 2009, by and among Enterprise Products Operating LLC and Enterprise GTM Holdings L.P. as Sellers and Duncan Energy Partners L.P. as Buyer (incorporated by reference to Exhibit 1.2 to Form 8-K filed June 18, 2009).
10.47	Term Loan Agreement, dated as of April 18, 2008, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto, Wachovia Bank, National Association, as Administrative Agent, Suntrust Bank and The Bank of Nova Scotia, as Co-Syndication Agents, Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland plc, as Co-Documentation Agents, and Wachovia Capital Markets, LLC, SunTrust Robinson Humphrey, a division of SunTrust Capital Markets, Inc. and The Bank of Nova Scotia, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.7 of Form 8-K filed December 8, 2008).

10.48	First Amendment to Term Loan Agreement, dated as of July 11, 2008, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto, Wachovia Bank, National Association, as Administrative Agent, Suntrust Bank and The Bank of Nova Scotia, as Co-Syndication Agents, Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland plc, as Co-Documentation Agents, and Wachovia Capital Markets, LLC, SunTrust Robinson Humphrey, a division of SunTrust Capital Markets, Inc. and The Bank of Nova Scotia, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.8 of Form 8-K filed December 8, 2008).
10.49	Second Amendment to Term Loan Agreement, dated October 25, 2010, among Duncan Energy Partners L.P., 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 10.01 to Form 8-K filed on October 26, 2010).
10.50	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 on June 3, 2010).
10.51	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 on August 23, 2010).
10.52	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 on October 26, 2010).
10.53***	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 by Enterprise Products Partners L.P. on October 14, 2010).
10.54***	Retention Agreement between W. Randall Fowler and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise Products Partners L.P. on December 10, 2010).
10.55***	Retention Agreement between A. James Teague and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise Products Partners L.P. on 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.
31.1#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Duncan Energy Partners L.P. for the December 31, 2010 Annual Report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Duncan Energy Partners L.P. for the December 31, 2010 Annual Report on Form 10-K.
32.1#	Section 1350 certification of W. Randall Fowler for the December 31, 2010 Annual Report on Form 10-K.
32.2#	Section 1350 certification of Bryan F. Bulawa for the December 31, 2010 Annual Report on Form 10-K.

* With respect to exhibits incorporated by reference to Exchange Act filings, the Commission file numbers for Duncan Energy Partners L.P., Enterprise Products Partners L.P. and Enterprise GP Holdings L.P. are 1-33266, 1-14323 and 1-32610, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

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.

DUNCAN ENERGY PARTNERS L.P.
(A Delaware Limited Partnership)

By: DEP 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

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 DEP Holdings, LLC)
/s/ W. Randall Fowler W. Randall Fowler	Director, President and Chief Executive Officer
/s/ Bryan F. Bulawa Bryan F. Bulawa	Director, Senior Vice President, Treasurer and Chief Financial Officer
/s/ Larry J. Casey Larry J. Casey	Director
/s/ William A. Bruckmann, III William A. Bruckmann, III	Director
/s/ Richard S. Snell Richard S. Snell	Director
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

DUNCAN ENERGY PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of DEP Holdings, LLC and
Unitholders of Duncan Energy Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Duncan Energy 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 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, such consolidated financial statements present fairly, in all material respects, the financial position of Duncan Energy 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.

As discussed in Note 1 to the Consolidated Financial Statements, the accompanying financial statements have been prepared from the separate records maintained by Enterprise Products Partners L.P. or affiliates and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2011

DUNCAN ENERGY PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32.4	$ 3.9
Accounts receivable – trade, net of allowance for doubtful accounts of $0.4 and less than $0.1 at December 31, 2010 and 2009, respectively.	66.0	77.7
Accounts receivable – related parties	21.1	54.5
Gas imbalance receivables	11.5	9.8
Inventories	5.8	10.5
Prepaid and other current assets	19.3	9.8
Total current assets	156.1	166.2
Property, plant and equipment, net	5,362.2	4,549.6
Investment in Evangeline	6.4	5.6
Intangible assets, net of accumulated amortization of $50.8 and $42.6 at December 31, 2010 and 2009, respectively.	38.0	43.8
Goodwill	4.9	4.9
Other assets	4.3	0.7
Total assets	$ 5,571.9	$ 4,770.8
LIABILITIES AND EQUITY		
Current liabilities:		
Current Maturities of Long-Term Debt	$ 282.3	$ --
Accounts payable – trade	99.3	54.5
Accounts payable – related parties	26.8	13.6
Accrued product payables	60.5	59.9
Accrued taxes	30.7	17.5
Other current liabilities	28.0	18.9
Total current liabilities	527.6	164.4
Long-term debt (see Note 11)	506.0	457.3
Deferred tax liabilities	5.3	5.8
Other long-term liabilities	13.4	6.4
Commitments and contingencies		
Equity:		
Partners' equity: (see Note 12)		
Limited partners:		
Common units (57,749,158 and 57,676,987 common units outstanding at December 31, 2010 and 2009, respectively)	760.3	766.6
General partner	0.1	0.2
Accumulated other comprehensive loss	--	(5.4)
Total partners' equity	760.4	761.4
Noncontrolling interest in subsidiaries: (see Note 13)		
DEP I Midstream Businesses – Parent	686.7	487.3
DEP II Midstream Businesses – Parent	3,072.5	2,888.2
Total noncontrolling interest	3,759.2	3,375.5
Total equity	4,519.6	4,136.9
Total liabilities and equity	$ 5,571.9	$ 4,770.8

See Notes to Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions)

	For Year Ended December 31,		
	2010	**2009**	**2008**
Revenues:			
Third parties	$ 537.3	$ 492.0	$ 856.4
Related parties	577.8	487.3	741.7
Total revenues (see Note 14)	1,115.1	979.3	1,598.1
Costs and Expenses:			
Operating costs and expenses:			
Third parties	860.4	749.0	1,167.7
Related parties	170.0	159.3	345.1
Total operating costs and expenses	1,030.4	908.3	1,512.8
General and administrative costs:			
Third parties	2.5	0.3	3.4
Related parties	17.5	10.9	14.9
Total general and administrative costs	20.0	11.2	18.3
Total costs and expenses (see Note 14)	1,050.4	919.5	1,531.1
Equity in income of Evangeline	0.8	1.1	0.9
Operating income	65.5	60.9	67.9
Other income (expense)			
Interest expense	(12.1)	(14.0)	(12.0)
Other, net	--	0.2	0.5
Other expense, net	(12.1)	(13.8)	(11.5)
Income before provision for income taxes	53.4	47.1	56.4
Provision for income taxes	--	(1.3)	(1.1)
Net income	53.4	45.8	55.3
Net loss (income) attributable to noncontrolling interest: (see Note 13)			
DEP I Midstream Businesses - Parent	(27.7)	(15.3)	(11.4)
DEP II Midstream Businesses - Parent	64.4	60.6	4.0
Total net loss (income) attributable to noncontrolling interest	36.7	45.3	(7.4)
Net income attributable to Duncan Energy Partners L.P. (see Note 1)	$ 90.1	$ 91.1	$ 47.9
Allocation of net income attributable to Duncan Energy Partners L.P.: (see Note 1)			
Limited partners' interest in net income	$ 89.5	$ 90.5	$ 27.8
General partner interest in net income	$ 0.6	$ 0.6	$ 0.5
Former owners of DEP II Midstream Businesses			$ 19.6
Basic and diluted earnings per unit (see Note 16)	$ 1.55	$ 1.57	$ 1.22

See Notes to Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For Year Ended December 31,		
	2010	**2009**	**2008**
Net income	$ 53.4	$ 45.8	$ 55.3
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instrument losses during period	--	--	(0.7)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	--	--	0.7
Interest rate derivative instrument losses during period	(0.2)	(2.5)	(8.0)
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	5.6	6.6	2.0
Total other comprehensive income (loss)	5.4	4.1	(6.0)
Comprehensive income	58.8	49.9	49.3
Comprehensive loss (income) attributable to noncontrolling interest:			
DEP I Midstream Businesses – Parent	(27.7)	(15.3)	(11.4)
DEP II Midstream Businesses – Parent	64.4	60.6	4.0
Total comprehensive loss (income) attributable to noncontrolling interest	36.7	45.3	(7.4)
Comprehensive income allocated to former owners of DEP II Midstream Businesses	--	--	(19.6)
Comprehensive income attributable to Duncan Energy Partners L.P.	$ 95.5	$ 95.2	$ 22.3

See Notes to Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For Year Ended December 31,		
	2010	**2009**	**2008**
Operating activities:			
Net income	$ 53.4	$ 45.8	$ 55.3
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	205.7	188.3	167.8
Non-cash asset impairment charges	5.2	4.2	--
Equity in income of Evangeline	(0.8)	(1.1)	(0.9)
Losses (gains) from asset sales and related transactions	7.9	(0.5)	(0.5)
Deferred income tax expense	(0.5)	--	0.3
Changes in fair market value of derivative instruments	--	(0.2)	(0.1)
Net effect of changes in operating accounts (see Note 19)	39.5	(34.9)	(1.8)
Cash flows provided by operating activities	310.4	201.6	220.1
Investing activities:			
Capital expenditures	(985.1)	(389.1)	(759.5)
Contributions in aid of construction costs	9.9	5.7	9.9
Proceeds from sale of assets and related transactions	2.4	0.9	0.9
Other, including loans to EPO (see Note 15)	45.5	(46.3)	(0.1)
Cash used in investing activities	(927.3)	(428.8)	(748.8)
Financing activities:			
Borrowings under bank agreements	422.1	76.2	398.9
Repayments of debt under bank agreements	(91.1)	(103.2)	(114.7)
Borrowings under Loan Agreement with EPO (see Note 11)	150.0	--	--
Repayments of Loan Agreement with EPO	(150.0)	--	--
Debt issuance costs	(6.9)	(0.4)	(1.6)
Cash distributions to our unitholders and general partner	(104.3)	(88.9)	(34.4)
Cash distributions to EPO as noncontrolling interest	(93.7)	(51.6)	(318.1)
Cash contributions from EPO as noncontrolling interest	517.6	386.0	183.3
Net cash proceeds from the issuance of common units	1.7	137.4	0.5
Repurchase of our common units from EPO (see Note 12)	--	(137.4)	--
Net cash contributions from former owners of the DEP II Midstream Businesses	--	--	425.6
Cash provided by financing activities	645.4	218.1	539.5
Net changes in cash and cash equivalents	28.5	(9.1)	10.8
Cash and cash equivalents, January 1	3.9	13.0	2.2
Cash and cash equivalents, December 31	$ 32.4	$ 3.9	$ 13.0

See Notes to Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 12 for Unit History)
(Dollars in millions)

	Former Owners DEP II Midstream Businesses	Duncan Energy Partners: Limited Partners	Duncan Energy Partners: General Partner	Duncan Energy Partners: Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest in Subsidiaries	Total
Balance, December 31, 2007	$ 2,880.1	$ 317.7	$ 0.6	$ (3.6)	$ 355.2	$ 3,550.0
Transactions prior to the DEP II drop down on December 8, 2008:						
Net income – January 1, 2008 through December 7, 2008	19.6	21.1	0.4	--	12.0	53.1
Amortization of equity-based awards	--	0.2	--	--	--	0.2
Cash contributions from former owner	425.6	--	--	--	--	425.6
Cash contributions from EPO as noncontrolling interest	--	--	--	--	161.6	161.6
Cash distributions to EPO as noncontrolling interest	--	--	--	--	(37.3)	(37.3)
Cash distributions to our unitholders and general partner	--	(33.7)	(0.7)	--	--	(34.4)
Change in value of cash flow hedges	--	--	--	(0.3)	--	(0.3)
Other	0.2	--	--	--	(12.5)	(12.3)
Balance, December 7, 2008	3,325.5	305.3	0.3	(3.9)	479.0	4,106.2
Transactions in connection with the DEP II drop down on December 8, 2008:						
Retention by noncontrolling interest of ownership interests	(2,595.5)	--	--	--	2,595.5	--
Allocation of equity in the DEP II Midstream Businesses to Duncan Energy Partners	(730.0)	730.0	--	--	--	--
Cash distribution paid to EPO as noncontrolling interest at DEP II drop down	--	(280.5)	--	--	--	(280.5)
Net cash proceeds from the issuance of common units	--	0.5	--	--	--	0.5
Balance, December 8, 2008	$ --	755.3	0.3	(3.9)	3,074.5	3,826.2
Net income (loss) – December 8, 2008 through December 31, 2008		6.7	0.1	--	(4.6)	2.2
Cash contributions from EPO as noncontrolling interest		--	--	--	21.7	21.7
Cash distributions to EPO as noncontrolling interest		--	--	--	(0.3)	(0.3)
Change in value of cash flow hedges		--	--	(5.7)	--	(5.7)
Other		--	--	--	0.1	0.1
Balance, December 31, 2008		762.0	0.4	(9.6)	3,091.4	3,844.2
Net income (loss)		90.5	0.6	--	(45.3)	45.8
Amortization of equity-based awards		2.2	--	--	--	2.2
Net cash proceeds from the issuance of common units		137.4	--	--	--	137.4
Cash contributions from EPO as noncontrolling interest		--	--	--	386.0	386.0
Cash distributions to EPO as noncontrolling interest		--	--	--	(51.6)	(51.6)
Cash distributions to our unitholders and general partner		(88.1)	(0.8)	--	--	(88.9)
Common units repurchased from EPO and retired (see Note 12)		(137.4)	--	--	--	(137.4)
Change in value of cash flow hedges		--	--	4.2	--	4.2
Other		--	--	--	(5.0)	(5.0)
Balance, December 31, 2009		766.6	0.2	(5.4)	3,375.5	4,136.9
Net income (loss)		89.5	0.6	--	(36.7)	53.4
Amortization of equity-based awards		5.9	0.1	--	--	6.0
Net cash proceeds from the issuance of common units		1.7	--	--	--	1.7
Cash contributions from EPO as noncontrolling interest		--	--	--	517.6	517.6
Cash distributions to EPO as noncontrolling interest		--	--	--	(93.7)	(93.7)
Cash distributions to our unitholders and general partner		(103.6)	(0.7)	--	--	(104.3)
Change in value of cash flow hedges		--	--	5.4	--	5.4
Other		0.2	(0.1)	--	(3.5)	(3.4)
Balance, December 31, 2010		$ 760.3	$ 0.1	$ --	$ 3,759.2	$ 4,519.6

See Notes to Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Except per unit amounts, or as noted within the context of each footnote disclosure, 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,” or “Duncan Energy Partners” are intended to mean the business and operations of Duncan Energy Partners L.P. and its consolidated subsidiaries. References to “DEP GP” mean DEP Holdings, LLC, which is our general partner. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. References to “DEP OLP” mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners. Duncan Energy Partners conducts substantially all of its business through DEP OLP and its consolidated subsidiaries.

References to “Enterprise” mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise 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 “EPD.” 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 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”). References to “EPO” mean Enterprise Products Operating LLC, whic h is a wholly owned subsidiary of Enterprise and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. EPO beneficially owns 100% of DEP GP and currently owns 58.5% of our common units. Enterprise consolidates our financial statements with its own. See Note 21 for information regarding Enterprise’s February 22, 2011 offer to acquire all of our outstanding publicly-held common units.

On September 3, 2010, Enterprise GP Holdings L.P. (“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.

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 Enterprise GP, currently Michael A. Creel, will appoint the successor Independent Voting Trustee(s).

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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.

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, Enterprise, EPO, DEP GP, 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 an d 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 a s the independent co-executors of the estate of Mr. Duncan.

References to the “DEP I Midstream Businesses” collectively refer to (i) Mont Belvieu Caverns, LLC (“Mont Belvieu Caverns”); (ii) Acadian Gas, LLC (“Acadian Gas”); (iii) Enterprise Lou-Tex

Propylene Pipeline L.P. (“Lou-Tex Propylene”), including its general partner; (iv) Sabine Propylene Pipeline L.P. (“Sabine Propylene”), including its general partner; and (v) South Texas NGL Pipelines, LLC (“South Texas NGL”). We acquired controlling ownership interests in the DEP I Midstream Businesses from EPO effective February 1, 2007 in a drop down transaction (the “DEP I drop down”) in connection with our initial public offering.

References to the “DEP II Midstream Businesses” collectively refer to (i) Enterprise GC, L.P. (“Enterprise GC”); (ii) Enterprise Intrastate L.P. (“Enterprise Intrastate”); and (iii) Enterprise Texas Pipeline LLC (“Enterprise Texas”). We acquired controlling ownership interests in the DEP II Midstream Businesses from EPO on December 8, 2008 in a drop down transaction (the “DEP II drop down”).

References to “Evangeline” mean our collective 49.51% equity method investment in Evangeline Gas Pipeline Company, L.P. (“EGP”) and Evangeline Gas Corp (“EGC”).

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 subsidiaries of Enterprise 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.” 0;Enterprise owns noncontrolling interests in Energy Transfer Equity, which it accounts for using the equity method of accounting

References to the “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.

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 “DEP.” We were formed in September 2006 and did not own any assets prior to February 5, 2007, which was the date we completed our initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. Our business purpose is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates of EPCO that are under common control. We are engaged in the business of (i) NGL transportation, fractionation and marketing; (ii) storage of NGL, petrochemical and refined products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, m arketing and storage of natural gas. Our assets, located primarily in Texas and Louisiana, include: 11,201 miles of natural gas, NGL and petrochemical pipelines; two NGL fractionation facilities; approximately 17.3 million barrels (“MMBbls”) of leased NGL storage capacity; 8.1 billion cubic feet (“Bcf”) of leased natural gas storage capacity; and 34 underground salt dome caverns with approximately 100 MMBbls of NGL and related product storage capacity. Our assets are integral to EPO’s midstream energy operations and are located near significant natural gas production basins such as the Eagle Ford Shale, Barnett Shale and Haynesville Shale.

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We have three reportable business segments: (i) Natural Gas Pipelines & Services; (ii) NGL Pipelines & Services; and (iii) Petrochemical Services. 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.

At December 31, 2010 we are owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP. EPO beneficially owned approximately 58.5% of our limited partner interests and 100% of DEP GP. See Note 21 for information regarding Enterprise's February 22, 2011 offer to acquire all of our outstanding publicly-held common units.

We, DEP GP, EPO, Enterprise, Enterprise GP, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and 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 related party matters.

We acquired controlling ownership interests in our consolidated subsidiaries through two drop down transactions, the DEP I and DEP II drop downs, which were sponsored by EPO. The following information summarizes the businesses acquired in connection with the DEP I and DEP II drop down transactions.

DEP I Drop Down

Effective February 1, 2007, EPO contributed to us a 66% controlling equity interest in each of the DEP I Midstream Businesses in a drop down transaction. EPO retained the remaining 34% noncontrolling equity interest in each of these businesses.

The following is a brief description of the assets and operations of the DEP I Midstream Businesses:

§ Mont Belvieu Caverns owns 34 underground salt dome storage caverns located in Mont Belvieu, Texas, having an NGL and related product storage capacity of approximately 100 MMBbls, and a brine system with approximately 20 MMBbls of above ground storage capacity and related brine production wells.

§ Acadian Gas is engaged in the gathering, transportation, storage and marketing of natural gas in south Louisiana, utilizing over 1,000 miles of pipelines having an aggregate throughput capacity of approximately 1.1 billion cubic feet per day ("Bcf/d"). Acadian Gas also owns a 49.51% equity interest in Evangeline, which owns a 27-mile natural gas pipeline located in southeast Louisiana.

In October 2009, we and EPO announced plans for our jointly owned Acadian Gas System to extend its Louisiana intrastate natural gas pipeline system into northwest Louisiana to provide producers in the Haynesville Shale production area with access to additional markets in central and southern Louisiana and connections to nine third-party major interstate natural gas pipelines. This expansion capital project is referred to as the "Haynesville Extension" of the Acadian Gas System. As currently designed, the Haynesville Extension will have the potential capacity to transport up to 1.8 Bcf/d of natural gas from the Haynesville area through a 270-mile pipeline that will connect with our existing Acadian Gas System. The Haynesville Extension 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, we agreed to fund 66% of the Haynesville Extension project costs and EPO agreed to fund the remaining 34% of such expenditures; therefore, we estimate that our share of such costs will approximate $1.03 billion. In order to fund our capital spending requirements under the Haynesville Extension project, we entered into new long-term senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010.

For information regarding our agreements with EPO related to the Haynesville Extension, see Note 15. For information regarding our $1.25 billion credit facilities, see Note 11.

- § Lou-Tex Propylene owns a 267-mile pipeline used to transport chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas.

- § Sabine Propylene owns a 21-mile pipeline used to transport polymer-grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana.

- § South Texas NGL owns a 297-mile pipeline system used to transport NGLs from our Shoup and Armstrong NGL fractionation facilities in South Texas to Mont Belvieu, Texas.

DEP II Drop Down

On December 8, 2008, EPO contributed to us the following controlling equity interests in a second drop down transaction: (i) a 66% voting general partner interest in Enterprise GC, (ii) a 51% voting general partner interest in Enterprise Intrastate and (iii) a 51% voting membership interest in Enterprise Texas. As consideration for these equity interests, we paid $280.5 million in cash and issued 37,333,887 Class B units to EPO (which automatically converted on a one-for-one basis to common units in February 2009). The cash portion of this consideration was financed with $280.0 million in borrowings under our Term Loan Agreement (see Note 11) and $0.5 million of net cash proceeds from an equity offering to EPO. The market valu e of the Class B units at the time of issuance was approximately $449.5 million. The following is a brief description of the assets and operations of the DEP II Midstream Businesses:

- § Enterprise GC operates and owns: (i) two NGL fractionation facilities, the Shoup and Armstrong facilities, located in South Texas; (ii) a 1,185-mile NGL pipeline system located in South Texas; and (iii) 1,096 miles of natural gas gathering pipelines located in South and West Texas. Enterprise GC’s natural gas gathering pipelines include: (i) the 262-mile Big Thicket Gathering System located in southeast Texas; (ii) the 660-mile Waha system located in the Permian Basin of west Texas; and (iii) the 174-mile TPC Offshore gathering system located in South Texas.

- § Enterprise Intrastate operates and owns an undivided 50% interest in the assets comprising the 641-mile Channel natural gas pipeline, which extends from the Agua Dulce Hub in South Texas to Sabine, Texas located on the Texas/Louisiana border.

- § Enterprise Texas owns the 6,653-mile Enterprise Texas natural gas pipeline system, which includes the Sherman Extension and Trinity River Lateral pipelines, and leases the Wilson natural gas storage facility. The Enterprise Texas pipeline system and the Wilson storage facility, along with the Waha, TPC Offshore and Channel pipeline systems, comprise our Texas Intrastate System.

  In July 2010, we completed and placed into service the final segment of our Trinity River Lateral natural gas pipeline. In total, the Trinity River Lateral pipeline extends approximately 40 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 Bcf/d of production takeaway capacity.

  Our Texas Intrastate System is strategically located to benefit from increasing natural gas production from the Eagle Ford Shale supply basin located in South Texas. We are in the process of expanding this system’s natural gas gathering and transportation capabilities as well as increasing our natural gas storage capacity to handle the expected increase in production volumes. EPO is funding 100% of the growth capital spending associated with these expansion projects.

See “DEP II Midstream Businesses – Parent” under Note 13 and “Significant Relationships and Agreements with EPO – Company and Limited Partnership Agreements – DEP II Midstream Businesses” under Note 15 for additional information regarding the DEP II Midstream Businesses.

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (the “Tier I distribution,” based on our $730.0 million aggregate investment) and then to EPO (the “Tier II distribution”), in amounts sufficient to generate an annualized return to both owners based on their respective investments. Distributions in excess of these amounts (the “Tier III distributions”) will be allocated 98% to EPO and 2% to us.

The initial annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, which was based on our estimated weighted-average cost of capital at December 8, 2008 plus 1.0%. The annualized return rate increases by 2.0% on January 1 of each year. As a result, the annualized return rate for 2010 was 12.087% and for 2011 will be 12.329%.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity’s percentage interest of 22.6% and 77.4%, respectively, and then in a manner that in part follows the cash distributions paid by (or contributions made to) each DEP II Midstream Business. The 22.6% and 77.4% amounts represent each owner’s initial relative economic investment in the DEP II Midstream Businesses at December 8, 2008.

See Note 13 for detailed information regarding EPO’s noncontrolling interest in the DEP I and DEP II Midstream Businesses.

Basis of Presentation

Our consolidated financial statements have been prepared in accordance with generally accepted accounting principles (“GAAP”) in the United States. Due to common control considerations, each of the DEP I drop down and DEP II drop down transactions was accounted for at EPO’s historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. Our consolidated financial statements for the year ended December 31, 2008 reflect the following:

§ Combined financial information of the DEP II Midstream Businesses from January 1, 2008 through December 7, 2008. The results of operations and cash flows of the DEP II Midstream Businesses for this period are allocated to the former owners of these businesses that are under common control with Duncan Energy Partners.

§ Consolidated financial information for Duncan Energy Partners for the twelve months ended December 31, 2008, including the results of operations and cash flows for the DEP II Midstream Businesses following completion of the DEP II drop down transaction. On December 8, 2008, the DEP II Midstream Businesses became consolidated subsidiaries of Duncan Energy Partners. EPO’s retained ownership in the DEP II Midstream Businesses (following the December 8, 2008 drop down transaction) is presented in our consolidated financial statements as “Noncontrolling interest in subsidiaries – DEP II Midstream Businesses – Parent.”

The financial statements of the DEP II Midstream Businesses were prepared from the separate records maintained by EPO and may not necessarily be indicative of the conditions that would have existed or the results of operations if the DEP II Midstream Businesses had operated as unaffiliated entities. All intercompany balances and transactions have been eliminated in consolidation. Transactions between EPO and us have been identified in our consolidated financial statements as transactions between affiliates.

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) our 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 esti mates 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 indicated:

	For Year Ended December 31,		
	2010	2009	2008
Balance at beginning of period	$ *	$ *	$ *
Charges to expense	0.4	--	--
Deductions	*	*	--
Balance at end of period	$ 0.4	$ *	$ *

* Amounts are negligible.

See “Credit Risk Due to Industry Concentrations” in Note 18 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.

The DEP II Midstream Businesses operated within the EPO cash management program prior to their drop down transaction date of December 8, 2008. For purposes of presentation in our Statements of Consolidated Cash Flows, cash flows provided by (or used in) financing activities during the pre-drop down timeframe represents transfers of excess cash from the DEP II Midstream Businesses to their former owners in amounts equal to any excess of net cash flow provided by operating activities over cash used in investing activities. Such transfers of excess cash are shown as permanent distributions to former owners on our Stat ements of Consolidated Equity. Conversely, if cash used in investing activities was greater than net cash flow provided by operating activities, then a deemed permanent contribution by the former owners was recognized. As a result, our financial statements do not reflect cash balances for the DEP II Midstream Businesses prior to their drop down transaction date. Following the DEP II drop down transaction, the respective businesses ceased participation in the EPO cash management program and maintain cash balances separately from affiliates.

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 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. Parent company ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 13 f or information regarding noncontrolling interest.

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If an 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 investee'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 investee'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 B alance 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 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 potential 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 $6.1 million and $4.5 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 additional information regarding our revenue recognition policies.

Derivative Instruments

We use derivative instruments such as physical forward agreements, futures contracts, floating-to-fixed swaps, basis swaps and options contracts to manage price risks associated with inventories, firm commitments, interest rates 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. See Note 16 for more information regarding our earnings per unit.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's 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 indicated:

	For Year Ended December 31,		
	2010	2009	2008
Balance at beginning of period	$ 0.5	$ 0.6	$ 17.8
Charges to expense	0.3	0.1	0.3
Charges to other accounts	0.5	--	0.2
Adjustments (1)	(0.3)	(0.2)	(17.7)
Balance at end of period	$ 1.0	$ 0.5	$ 0.6

(1) The $17.7 million deduction in 2008 in the reserve balance is partially comprised of a $5.0 million reduction in the reserve based on revised estimates of future remediation costs and a remaining $6.3 million reserve retained by EPO in connection with the DEP II drop down transaction. In addition, we spent approximately $5.4 million for the remediation of mercury site contamination in 2008.

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 (e.g., assets, liabilities, revenue and expenses) and disclosures regarding 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.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable, 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 carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 6 for additional 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	$ 32.4	$ 32.4	$ 3.9	$ 3.9
Accounts receivable	98.6	98.6	142.0	142.0
Financial liabilities:				
Accounts payable and accrued expenses	$ 217.3	$ 217.3	$ 145.5	$ 145.5
Other current liabilities	27.8	27.8	13.3	13.3
Variable-rate debt	788.3	788.3	457.3	457.3

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. 60; We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 10 for additional information regarding our goodwill.

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 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 absen ce of such data, appropriate valuation techniques. See Note 6 for information regarding impairment charges recorded during 2010 and 2009.

Impairment Testing for Unconsolidated Affiliate

We evaluate our equity method investment 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 relates to our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax"). In general, legal entities that conduct business in Texas are subject to the Texas Margin Tax. Such amounts are considered immaterial to our financial statements.

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 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.

Inventories

Our inventory consists of natural gas volumes that are used either for operational system balancing or held in connection with forward sales contracts. We occasionally recognize lower of average cost or market ("LCM") adjustments when the historical cost of our forward sales inventory exceeds its net realizable value. These non-cash adjustments are recorded as a component of cost of sales within operating costs and expenses. The capitalized cost of our inventory held in connection with forward sales contracts includes shipping and handling charges that are directly related to purchased volumes. As volumes are delivered out of inventory, the cost of such inv entory is charged to cost of sales, which is a component of operating costs and expenses. Transportation and handling fees associated with products we deliver to customers are charged to operating costs and expenses as incurred. The natural gas volumes used for operational system balancing fluctuate as a result of imbalances with shippers and are valued based on a twelve-month rolling average of posted industry prices. When such volumes are delivered out of inventory, the average cost of these volumes is charged against our accrued gas imbalance payables. 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 e vents 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, 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. T he vast majority of such settlements are through in-kind arrangements whereby an imbalance volume is incrementally delivered to or received from a customer over one or more periods.In some cases, settlements of imbalances 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 those gas imbalances that are ultimately settled over future periods, we estimate and accrue 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	$ 11.5	$ 9.8
Natural gas imbalance payables (1)	10.6	11.0

(1) 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.

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.

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 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 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 the notes to our 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.□ 0; Currently, 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:

Natural Gas Pipelines & Services

The Natural Gas Pipelines & Services segment includes approximately 9,400 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Louisiana and Texas. In addition, we lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Our 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 Texas Railroad Commission. Certain of our 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.

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. Revenue from these sales contracts is recognized when the natural gas is delivered to customers.

Revenues from natural gas storage contracts typically have 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. Revenues from demand payments are recognized during the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

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. Revenues from these sales contracts are 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.

NGL Pipelines & Services

The NGL Pipelines & Services segment includes our (i) NGL marketing activities related to our Big Thicket Gathering System; (ii) NGL pipelines aggregating 1,482 miles; (iii) NGL and related product storage facilities and (iv) NGL fractionation facilities.

The NGL marketing activities of our Big Thicket Gathering System generate revenues from the sale and delivery of NGLs we take title to through natural gas processing agreements at EPO’s Indian Springs natural gas processing plant located in East Texas. Revenue associated with these agreements is recognized when the NGLs are delivered to customers. The results of operations from our NGL marketing activities are generally dependent upon the volume of products sold and the market-based sales prices charged to customers.

Under our NGL pipeline transportation contracts, revenue is recognized when volumes have been delivered to customers or processed at our Shoup and Armstrong NGL fractionators. Revenues recorded by our subsidiary South Texas NGL from its NGL transportation agreement with EPO are based on a fixed fee per gallon of liquids multiplied by the total volume of NGLs processed at the Shoup and Armstrong

NGL fractionators whether or not such NGL volumes are transported on the pipeline owned by South Texas NGL (such pipeline being a component of the South Texas NGL System). Revenue from the remainder of our NGL transportation contracts is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are contractual and not typically regulated by governmental agencies.

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). 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 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. In addition, we generally collect throughput fees wh en customers place volumes into and withdraw volumes from storage. We derive brine production revenues from customers that use brine in the production of feedstocks for polyvinyl chloride.

We enter into fee-based arrangements for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided based on a contractual fee (typically in cents per gallon) and the volume processed by our NGL fractionators.

Petrochemical Services

The Petrochemical Services segment consists of our petrochemical pipelines aggregating 288 miles. Revenues recorded for the Lou-Tex Propylene Pipeline and Sabine Propylene Pipeline are primarily based on exchange agreements with Shell Oil Company and Exxon Mobil Corporation ("Exxon Mobil"). As a result of these exchange agreements, we agree to receive propylene in one location and deliver propylene at another location for a fee. Revenue from these contracts is generally based upon a fixed fee per unit of volume of liquids transported multiplied by the volume delivered and may include deficiency fee provisions if certain minimum delivery requirements are not met.

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 indicated:

	For Year Ended December 31,		
	2010	2009	2008
Restricted common unit awards	$ 3.6	$ 1.4	$ 0.7
Unit option awards	0.3	0.2	--
Employee Partnerships	3.1	0.6	0.2
Total compensation expense	$ 7.0	$ 2.2	$ 0.9

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 potential liability-classified awards (e.g., unit appreciation rights ("UARs") and phantom units) would be 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 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (the "2010 Plan"), the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan").

The 2010 Plan, which became effective on February 11, 2010, provides for awards to employees, directors or consultants providing services to us. Awards under the 2010 Plan may be granted in the form of options to purchase our common units, restricted common units, UARs, phantom units and distribution equivalent rights ("DERs"). Up to 500,000 of our 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. All of the awards issued for which we have been allocated expense were in the form of restricted common units.

The 1998 Plan provides for awards of Enterprise's common units and other rights to 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 DERs. Up to 7,000,000 of Enterprise's 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 of Enterprise could be issued. All of the awards issued for which we have been allocated expense were in the form of unit options and restricted common units.

The 2008 Plan provides for awards of Enterprise's common units and other rights to 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, UARs, phantom units and DERs. Up to 10,000,000 of Enterprise's 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 of Enterprise could be issued. All of the awards issued for which we have been allocated expense were in the form of unit options and restricted common units.

Summary of Long-Term Incentive Awards

The following information is being provided regarding the 2010 Plan and EPCO's other long-term incentive awards under which we have received or may receive an allocation of expense. EPCO has certain plans under which liability-classified awards may be issued. As of December 31, 2010, we have not been allocated any costs of liability-classified awards and therefore have not included any discussion of such awards in these disclosures. EPCO may create additional long-term incentive plans in the future that may result in us receiving an allocation of expense based on services rendered to us by the recipients of such awards. Unless noted otherwise, the following information is presented on a gross basis (to EPCO and affiliates) with respect to the type of award granted. To the extent applicable, we have noted our estimated share of unrecognized compensation costs of such awards and the weighted-average period of time over which we expect to recognize such expense.

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 Enterprise 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.

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.

The following table presents information regarding restricted common unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise Products Partners L.P. 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 L.P. 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	--	

(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 Enterprise's 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 Enterprise's 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 Enterprise's 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 and DEP GP as part of their annual compensation in for 2010. A total of 6,960 and 6,348 restricted common unit awards were issued in February 2010 to the independent directors of EPGP and DEP GP, respectively, that immediately vested upon issuance.
(6) Aggregate grant date fair value of restricted common unit awards denominated in our common units issued during 2010 was $0.2 million based on a grant date market price of our common units of $25.26 per unit.

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 $4.9 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 Enterprise 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. There were no options granted under our 2010 Plan during the year ended December 31, 2010.

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 options, risk-free interest rates, expected distribution yield of the underlying security, and expected unit price volatility. In general, the 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. The 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 underl ying 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, Enterprise amended the terms of certain of its 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 Enterprise.

The following table presents unit option activity under the EPCO plans for the periods indicated. As of December 31, 2010, only Enterprise 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 Enterprise's common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) a risk-free interest rate of 3.3%; (iv) an expected distribution yield on Enterprise's common units of 7.0%; and (v) an expected unit price volatility on Enterprise's common units of 19.8%. An estimated forfeiture rate of 17.0% 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 Enterprise's 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 Enterprise's common units of 9.4%; and (v) weighted-average expected unit price volatility on Enterprise's common units of 57.4%. An estimated forfeiture rate of 17.0% 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 Enterprise's 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 Enterprise's common units of 6.9%; and (v) weighted-average expected unit price volatility on Enterprise's common units of 23.3%. An estimated forfeiture rate of 17.0% was applied to awards granted during 2010.
(5) Enterprise was committed to issue 3,753,420 and 3,825,920 of Enterprise's 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.

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 $0.7 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years.

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 Enterprise's common units or Holdings' units or a combination of both.

We recognized approximately $2.7 million of expense in connection with the liquidation of the Employee Partnerships, of which approximately $1.1 million was attributed to noncontrolling interest. Of this expense amount, approximately $1.7 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.

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 and commodity prices. 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 or commodity prices. 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 physical forward agreements, futures contracts, floating-to-fixed swaps, basis swaps and options contracts. Substantially all of our derivativ es 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 are related. 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.

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 changes in the 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 thi ngs, 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.

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 have no interest rate derivative instruments outstanding at December 31, 2010. We utilized floating-to-fixed interest rate swaps with a notional value of $175.0 million to manage our exposure to changes in the interest rates charged on borrowings under our $300.0 million unsecured revolving credit facility (the “Revolving Credit Facility”) from September 2007 through September 2010. Our interest rate swaps expired in September 2010. This strategy was a component in controlling our cost of capital associated with such borrowings.

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. Our interest rate swaps resulted in an increase in interest expense of $5.6 million, $6.5 million and $2.0 million, respectively, for the years ended December 31, 2010, 2009 and 2008.

Commodity Derivative Instruments

The price of natural gas is 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 forwards, basis swaps and futures contracts. The following table summarizes our commodity derivative instruments outstanding at December 31, 2010:

	Volume (1)		Accounting
Derivative Purpose	**Current**	**Long-Term**	**Treatment**
Derivatives not designated as hedging instruments:			
Acadian Gas:			
Natural gas risk management activities (2)	2.8 Bcf	n/a	Mark-to-market

(1) This reflects the absolute value of derivative notional volumes.
(2) Reflects the use of derivative instruments to manage risks associated with natural gas transportation and storage assets.

Our hedging strategy is intended to reduce the variability of future earnings and cash flows resulting from changes in natural gas prices. We enter into a limited number of forward transactions that effectively fix the price of natural gas for certain customers and hedge the resulting exposure with derivative instruments. We may also enter into a small number of cash flow hedges in connection with the purchase of natural gas held-for-sale to third parties.

Our general partner monitors the hedging strategies associated with these physical and financial risks, approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

Credit-Risk Related Contingent Features in Derivative Instruments

Commodity derivative instruments can include provisions related to minimum credit ratings and/or adequate assurance clauses. At December 31, 2010, we did not have any derivative instruments with contingent features in a net liability position. The potential for derivatives with contingent features to enter a net liability position may change in the future as 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	$ --	Other current assets	$ --	Other current liabilities	$ --	Other current liabilities	$ 5.5
Derivatives not designated as hedging instruments:								
Commodity derivatives	Other current assets	$ 0.2	Other current assets	$ 0.1	Other current liabilities	$ 0.2	Other current liabilities	$ 0.1

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 indicated:

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	$ (0.2)	$ (2.5)	$ (8.0)
Commodity derivatives	--	--	(0.7)
Total	$ (0.2)	$ (2.5)	$ (8.7)

Derivatives in Cash Flow Hedging Relationships	Location	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	$ (5.6)	$ (6.6)	$ (2.0)
Commodity derivatives	Operating revenue	--	--	(0.7)
		$ (5.6)	$ (6.6)	$ (2.7)

Derivatives in Cash Flow Hedging Relationships	Location	Gain Recognized in Income on Ineffective Portion of Derivative		
		For Year Ended December 31,		
		2010	2009	2008
Interest rate derivatives	Interest expense	$ *	$ 0.1	$ *

* Amount is negligible.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Statements of Consolidated Operations for the periods presented:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative		
		For Year Ended December 31,		
		2010	2009	2008
Commodity derivatives	Revenue	$ (0.7)	$ (0.6)	$ 0.7

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the ext ent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

- § Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values primarily consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

- § Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions are: (i) observable in the marketplace throughout the full term of the instrument; (ii) can be derived from observable data; or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity financial instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter. The fair values of these derivatives instruments are based on observable price quotes for similar products and locations. Our interest rate derivatives were valued by using appropriate financial models with the implied forward London Interbank Offered Rate ("LIBOR") yield curve for the same period as the future interest swap settlements.

- § Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inpu ts are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs. At December 31, 2010, we did not have any Level 3 financial assets or liabilities.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities at the dates indicated. These financial assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input that is significant to their respective fair value measurements. Our assessment of the relative significance of such inputs requires judgment. There were no transfers between Levels 1, 2 or 3 during the years ended December 31, 2010 and 2009.

	At December 31, 2010		
	Level 1	**Level 2**	**Total**
Financial assets:			
Commodity derivatives	$ 0.1	$ 0.1	$ 0.2
Financial liabilities:			
Commodity derivatives	$ 0.1	$ 0.1	$ 0.2

	At December 31, 2009		
	Level 1	Level 2	Total
Financial assets:			
Commodity derivatives	$ 0.1	$ *	$ 0.1
Financial liabilities:			
Commodity derivatives	$ *	$ 0.1	$ 0.1
Interest rate derivatives	--	5.5	5.5
Total derivative liabilities	$ *	$ 5.6	$ 5.6

* Amounts are negligible.

Nonfinancial Assets and Liabilities

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis (e.g., property, plant and equipment) and are subject to fair value adjustments under certain circumstances.

Using appropriate valuation techniques, we adjusted the carrying value of certain assets recorded as property, plant and equipment to an estimated fair value of $0.2 million during the year ended December 31, 2010. This resulted in non-cash asset impairment charges of $5.2 million. These impairment charges resulted primarily from the anticipated abandonment of certain pipeline laterals on our TPC Offshore gathering system and the cancellation of a compressor station project on our Texas Intrastate System. Our fair value estimates were based primarily on an evaluation of the future cash flows associated with each asset (Level 3).

During the year ended December 31, 2009, we adjusted the carrying value of certain assets recorded as property, plant and equipment to an estimated fair value of $1.8 million based on an evaluation of future cash flows (Level 3). These adjustments resulted in non-cash asset impairment charges totaling $4.2 million. These impairment charges resulted from the cancellation of a compressor station project on our Texas Intrastate System in addition to anticipated abandonment activities related to a portion of this system.

The non-cash impairment charges we recorded during the years ended December 31, 2010 and 2009 are a component of operating costs and expenses.

Note 7. Inventories

Our inventory amounts were as follows at the dates indicated:

	December 31,	
	2010	2009
Working inventory (1)	$ 1.0	$ 4.4
Forward sales inventory (2)	4.8	6.1
Total inventory	$ 5.8	$ 10.5

(1) Working inventory is comprised of inventories of natural gas that are used in the provision for services.
(2) Forward sales inventory consists of identified natural gas volumes dedicated to the fulfillment of forward sales contracts.

Working inventory includes natural gas volumes held for operational system balancing on the Texas Intrastate System. These natural gas inventories fluctuate as a result of imbalances with shippers and are valued based on a twelve-month rolling average of posted industry prices. When such volumes are delivered out of inventory, the average cost of these volumes is charged against our accrued gas imbalance payables. At December 31, 2010 and 2009, the value of natural gas held in inventory for operational system balancing was $0.1 million and $2.8 million, respectively.

As a result of fluctuating market conditions, we occasionally recognize LCM adjustments when the historical cost of our forward sales inventory exceeds its net realizable value. These non-cash adjustments are recorded as a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 6 for a description of our commodity hedging activities. The following table summarizes our cost of sales and LCM adjustments for the periods indicated:

	For Year Ended December 31,		
	2010	2009	2008
Cost of sales (1)	$ 584.6	$ 490.0	$ 1,122.4
LCM adjustments	*	*	1.8

(1) Cost of sales is a component of "Operating costs and expenses", as presented on our Statements of Consolidated Operations. Year-to-year fluctuations in these amounts are primarily due to changes in natural gas prices and sales volumes.
* We recognized nominal LCM adjustments for the year ended December 31, 2010 and 2009.

Note 8. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	At December 31,	
		2010	2009
Plant and pipeline facilities (1)	3-45 (4)	$ 5,118.6	$ 4,767.0
Underground storage wells and related assets (2)	5-35 (5)	474.2	432.5
Transportation equipment (3)	3-10	13.0	11.3
Land		46.0	27.8
Construction in progress		807.4	233.6
Total		6,459.2	5,472.2
Less accumulated depreciation		1,097.0	922.6
Property, plant and equipment, net		$ 5,362.2	$ 4,549.6

(1) Includes natural gas, NGL and petrochemical pipelines, NGL fractionation facilities, office furniture and equipment, buildings and related assets.
(2) Underground storage facilities include product storage caverns and related assets such as pipes and compressors.
(3) Transportation equipment includes vehicles and similar assets used in our operations.
(4) In general, the estimated useful lives of major assets within this category are: pipelines, 18-45 years (with some equipment at 5 years); office furniture and equipment, 3-20 years; buildings, 20-35 years; and fractionation facilities, 28 years.
(5) In general, the estimated useful life of underground storage facilities is 20-35 years (with some components at 5 years).

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For Year Ended December 31,		
	2010	2009	2008
Depreciation expense (1)	$ 187.3	$ 176.7	$ 158.5
Capitalized interest (2, 3)	3.2	0.3	0.3

(1) Depreciation expense is a component of "Costs and expenses" as presented in our Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.
(3) The increase in capitalized interest for 2010 is due to our election to fund the Haynesville Extension in line with our respective ownership interest.

Haynesville Extension

On a consolidated basis, our construction in progress amount at December 31, 2010 includes $566.7 million of capital expenditures related to the Haynesville Extension project. Based on the current spending forecast for this project, we expect that consolidated capital spending (on a 100% basis, including capitalized interest) for the Haynesville Extension will approximate $930 million for 2011 and $1.56 billion for the entire project through completion, which is expected in September 2011.

Our 66% share of the total expected cost of the Haynesville Extension is estimated at $1.03 billion. We expect that our 66% share of the capital spending for this project in 2011 will approximate $614 million. For information regarding the funding of the Haynesville Extension, see "Significant Relationships and Agreements with EPO – Amended Acadian LLC Agreement" under Note 15.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our AROs primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain facilities. In addition, our AROs may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos. The following table presents information regarding our AROs since December 31, 2008.

ARO liability balance, December 31, 2008	$	4.6
Liabilities settled		(0.7)
Accretion expense		0.6
Revisions in estimated cash flows		5.9
ARO liability balance, December 31, 2009		10.4
Liabilities settled		(5.2)
Accretion expense		0.7
Revisions in estimated cash flows		9.7
ARO liability balance, December 31, 2010	$	15.6

The increase in our ARO liability balance during 2010 primarily reflects revised estimates of the cost to comply with regulatory abandonment obligations associated with above-ground brine storage pits at our Mont Belvieu storage facility.

Property, plant and equipment at December 31, 2010 and 2009 includes $9.4 million and $5.5 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents forecast accretion expense associated with our ARO's for the years presented:

2011		**2012**		**2013**		**2014**		**2015**	
$	1.0	$	1.1	$	1.2	$	1.2	$	1.3

Note 9. Investment in Evangeline

Acadian Gas, through a wholly owned subsidiary, owns a collective 49.51% equity interest in Evangeline, which consists of a 45% direct ownership interest in EGP and a 45.05% direct interest in EGC. EGC also owns a 10% direct interest in EGP. Third parties own the remaining equity interests in EGP and EGC. Acadian Gas does not have a controlling interest in the Evangeline entities, but does exercise significant influence on Evangeline's operating policies. Acadian Gas accounts for its investment in Evangeline using the equity method. Our investment in Evangeline is classified within the Natural Gas Pipelines & Services business segment.

Evangeline owns a 27-mile natural gas pipeline system (extending from Taft, Louisiana to Westwego, Louisiana) that is connected to three electric generation stations owned by Entergy Louisiana ("Entergy"). Evangeline's most significant contract is a natural gas sales agreement with Entergy. Evangeline is obligated to make available-for-sale and deliver to Entergy certain specified minimum contract quantities of natural gas on an hourly, daily, monthly and annual basis. The sales contract provides for minimum annual quantities of 36.8 billion British thermal units ("BBtus"), until the contract expires on January 1, 2013.

In connection with the Entergy sales contract, Evangeline has entered into a natural gas purchase contract with a subsidiary of Acadian Gas that contains annual purchase provisions. The pricing terms of the sales agreement with Entergy and Evangeline's purchase agreement with Acadian Gas are based on a weighted-average cost of natural gas each month (subject to certain market index price ceilings and incentive margins) plus a predetermined margin.

In 1991, Evangeline entered into an agreement with Entergy whereby Entergy was granted the right to acquire Evangeline's pipeline system for a nominal price, plus the assumption of all of Evangeline's obligations under the natural gas sales contract. The option period began on July 1, 2010 and terminates on December 31, 2012. While Entergy has expressed an interest in exercising this purchase option, we cannot ascertain when, or if, it will be exercised. This uncertainty results from various factors, including decisions by Entergy's management and regulatory approvals that may be required for Entergy to acquire Evangeline's assets.

We have received no cash distributions from Evangeline since we acquired our interest in Evangeline in April 2001. The trust indenture governing Evangeline's Series B notes (see "Evangeline Joint Venture Debt Obligations" under Note 11) placed restrictions on the payment of distributions to Evangeline's partners. The Series B notes were repaid in December 2010 and we expect to receive distributions from Evangeline in 2011. Our share of undistributed earnings of Evangeline totaled approximately $4.4 million at December 31, 2010. See Note 11 for a description of Evangeline's outstanding debt obligations.

The following tables present summarized financial information for Evangeline:

	At December 31,	
	2010	2009
BALANCE SHEET DATA:		
Current assets	$ 15.3	$ 24.4
Property, plant and equipment, net	2.4	3.2
Other assets	9.7	13.5
Total assets	$ 27.4	$ 41.1
Current liabilities	$ 13.0	$ 10.6
Other liabilities	*	17.7
Combined equity	14.4	12.8
Total liabilities and combined equity	$ 27.4	$ 41.1

* Amount is negligible.

	For Year Ended December 31,		
	2010	2009	2008
INCOME STATEMENT DATA:			
Revenues	$ 183.6	$ 164.5	$ 371.8
Operating income	2.0	3.7	7.2
Net income	1.5	2.2	1.8

Note 10. Intangible Assets and Goodwill

The following table summarizes our intangible asset balances by segment at the dates indicated:

	At December 31, 2010			At December 31, 2009		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 24.6	$ (11.0)	$ 13.6	$ 24.6	$ (8.9)	$ 15.7
Contract based intangibles	43.2	(29.5)	13.7	40.8	(24.7)	16.1
Natural Gas Pipelines & Services:						
Customer relationship intangibles	21.0	(10.3)	10.7	21.0	(9.0)	12.0
Total all segments	$ 88.8	$ (50.8)	$ 38.0	$ 86.4	$ (42.6)	$ 43.8

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For Year Ended December 31,		
	2010	2009	2008
NGL Pipelines & Services	$ 6.9	$ 7.1	$ 7.6
Natural Gas Pipelines & Services	1.3	1.4	1.5
Total segments	$ 8.2	$ 8.5	$ 9.1

Based on information currently available, the following table presents an estimate of future amortization expense associated with our intangible assets for the periods indicated:

	For Year Ended December 31,				
	2011	2012	2013	2014	2015
NGL Pipelines & Services	$ 6.4	$ 2.9	$ 1.7	$ 1.5	$ 1.4
Natural Gas Pipelines & Services	1.2	1.1	1.0	0.9	0.8
Total segments	$ 7.6	$ 4.0	$ 2.7	$ 2.4	$ 2.2

In general, our intangible assets fall within two categories: customer relationships and contract-based intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with our DEP I and DEP II drop down transactions. Contract-based intangible assets represent specific commercial rights arising from discrete contractual agreements acquired in connection with the aforementioned drop down transactions.

Customer relationship intangible assets. Our customer relationship intangible assets (i) supply us with information about or access to customers and (ii) grant customers the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. At December 31, 2010, the carrying value of our customer relationship intangible assets was $24.3 million.

The values assigned to our customer relationship intangible assets are being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying natural resource basins from which the customers produce are estimated to be consumed or otherwise used (based on proved reserves). Our estimate of the useful life of each natural resource basin is based on a number of factors, including third-party reserve estimates, our view of the economic viability of production and exploration activities and other industry factors.

Contract-based intangible assets. At December 31, 2010, the carrying value of our contract-based intangible assets was $13.7 million. Due to the renewable nature of the underlying contracts, we amortize the Mont Belvieu storage contracts on a straight-line basis over the estimated 26 years of remaining economic life of the storage assets to which they relate. The value assigned to the Markham NGL storage contracts is being amortized to earnings over its estimated 1.3 years of remaining economic life, using the straight-line method. The Mont Belvieu and Markham NGL storage contracts are included in our NGL Pipelines & Services segment.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. 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 at December 31, 2010 and 2009 was $4.9 million and represents an allocation to the DEP II Midstream Businesses of the goodwill recorded by Enterprise in connection with its merger with a third-party partnership in September 2004. The carrying value of our goodwill does not reflect any accumulated impairment charges.

Note 11. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	At December 31, 2010	At December 31, 2009
DEP Multi-Year Revolving Credit Facility, variable rate, due October 2013	$ 106.0	$ --
$400 Million Term Loan Facility, variable rate, due October 2013	400.0	--
Revolving Credit Facility, variable rate, repaid October 2010 (1)	--	175.0
Term Loan Agreement, variable rate, due December 2011	282.3	282.3
Total principal amount of debt obligations	$ 788.3	$ 457.3
Less: Current maturities of debt (2)	(282.3)	--
Total long-term debt	$ 506.0	$ 457.3

(1) This agreement was terminated on October 25, 2010 using proceeds from borrowings on our $400 Million Term Loan Facility.
(2) Current maturities of debt reflect the classification of such obligations at December 31, 2010.

DEP Multi-Year Revolving Credit Facility and $400 Million Term Loan Facility

In October 2010, to address our election to fund 66% of the Haynesville Extension pipeline project costs under the Amended Acadian LLC Agreement (see Note 15), we entered into new long-term variable rate unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion (collectively, the “Revolving Credit and Term Loan Agreement”). The new 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 “$400 Million Term Loan Facility”).

At December 31, 2010, principal outstanding under the $850.0 million DEP Multi-Year Revolving Credit Facility was $106.0 million. This revolving credit facility allows for up to $300.0 million of the borrowing capacity for issuing letters of credit, with a $75.0 million sublimit for swingline loans. If no event of default exists, we can increase the borrowing capacity of the DEP Multi-Year Revolving Credit Facility, without consent of the lenders, by an amount not exceeding $300.0 million by adding one or more new lenders and/or requesting that the existing lenders increase their commitments. No lender will be required to increase its commitment, unless it agrees to do so in its sole discretion.

At closing in October 2010, we borrowed the full amount available under the $400 Million Term Loan Facility. Any amounts repaid under this term loan cannot be reborrowed. At closing, these funds were used to repay principal amounts outstanding under our then existing Revolving Credit Facility and the $200 million revolving loan agreement with EPO (the “Loan Agreement with EPO”). Upon repayment of the principal amounts outstanding, both the Revolving Credit Facility and the Loan Agreement with EPO were terminated.

As defined within the Revolving Credit and Term Loan Agreement, principal amounts outstanding will accrue interest at the following rates: (i) LIBOR plus an applicable margin or (ii) a Base Rate. Under the agreement, LIBOR is defined as the rate per annum at which deposits in U.S. Dollars are offered in the London InterBank market as reported on Reuters at approximately 11:00 a.m., London time, two days prior to the borrowing date. The Base Rate is defined as the highest of (i) the rate of interest publicly announced by the administrative agent, Wells Fargo Bank, National Association, as its Base Rate, (ii) 0.5% per annum above the Federal Funds Rate in effect on such date, or (iii) 1.0% per annum above the LIBOR Market Interest Rate. The LIBOR Market Interest Rate is defined as the rate per annum at which deposits in U.S. dollars are offered on the London InterBank market as reported on Reuters at approximately 11:10 a.m., London time, for such day as the rate for a one-month maturity.

The Revolving Credit and Term Loan Agreement contains various operating and financial covenants, including those restricting or limiting our ability and the ability of certain of our subsidiaries to: (i) incur additional indebtedness, (ii) grant liens or make certain negative pledges, (iii) engage in certain asset conveyances, sales, transfers, leases or other dispositions of certain assets, businesses or operations; (iv) make certain investments; (v) enter into a merger, consolidation, or dissolution; (vi) engage in transactions with affiliates; (vii) directly or indirectly make or permit any payment on distribution in respect of our partnership interests; and (viii) permit or incur any limitation on the ability of any of our subsidiaries to pay dividends or make distributions, repay indebtedness, or make subordinated loans or advanc es, to us.

If an event of default exists under the Revolving Credit and Term Loan Agreement, the lenders will be able to accelerate the maturity of the credit facilities and exercise other rights and remedies. Each of the following is an event of default under the agreement: (i) non-payment of any principal, interest or fees when due under the credit agreement subject to grace periods to be negotiated; (ii) failure of any representation or warranty to be correct in any material respect; (iii) non-performance of covenants subject to grace periods to be negotiated; (iv) failure to pay any other material debt exceeding $25 million in the aggregate; (v) a change of control; and (vi) other customary defaults, including specified bankruptcy or insolvency events.

Revolving Credit Facility

This revolving credit facility was repaid in October 2010 using borrowings under the $400 Million Term Loan Facility. As defined in the credit agreement, variable interest rates charged under this facility were either at (i) a Eurodollar rate plus an applicable margin or (ii) a Base Rate.

Term Loan Agreement

In December 2008, we borrowed $282.3 million under our $300 million senior unsecured term loan agreement (the “Term Loan Agreement”) in order to fund cash consideration due to EPO in connection with the DEP II drop down transaction. Loans under the Term Loan Agreement may be prepaid at any time, subject to prior notice in accordance with the credit agreement. Loans under the Term Loan Agreement bear interest of the type specified in the applicable borrowing request, and consist of either Alternate Base Rate or Eurodollar loans (as defined in the credit agreement). The Term Loan Agreement contains certain financial and other customary affirmative and negative covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

Loan Agreement with EPO

In June 2010, we entered into the Loan Agreement with EPO. Our borrowings under this revolving loan agreement were primarily used to temporarily fund our share of project costs for the Haynesville Extension. The Loan Agreement with EPO was terminated in October 2010, and the principal amount of $125.0 million then outstanding was repaid using borrowing proceeds under our $400 Million Term Loan Facility. For the year ended December 31, 2010, we paid EPO commitment fees of $0.2

million and interest of $0.7 million in connection with this loan agreement. See Note 15 for information regarding our relationship with EPO.

Covenants

We were in compliance with the financial covenants of our debt agreements at December 31, 2010.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt obligations during the year ended December 31, 2010:

	Range of Interest Rates Paid	Weighted-average interest rate paid
DEP Multi-Year Revolving Credit Facility	2.00% to 2.02%	2.01%
$400 Million Term Loan Facility	2.25% to 2.26%	2.26%
Term Loan Agreement	0.93% to 1.09%	1.03%
Revolving Credit Facility	0.80% to 3.25%	0.95%
Loan Agreement with EPO	2.76% to 2.82%	2.81%

Evangeline Joint Venture Debt Obligations

The following table presents the debt obligations of Evangeline at the dates indicated:

	At December 31, 2010	At December 31, 2009
9.9% fixed interest rate senior secured notes due December 2010 (“Series B” notes)	$ --	$ 3.2
Subordinated note payable to an affiliate of other co-venture participant (“LL&E Note”)	3.2	7.5
Total joint venture debt principal obligation	$ 3.2	$ 10.7

Evangeline made a final scheduled principal repayment of $3.2 million on the Series B notes in December 2010.

The LL&E Note was subject to a subordination agreement which prevented the repayment of principal and accrued interest on the note until such time as the Series B note holders were either fully cash secured through debt service accounts or had been completely repaid. Variable rate interest accrues on the subordinated note at LIBOR plus 0.5%. The weighted-average variable interest rates charged on this note at December 31, 2010 and 2009 were 1.25% and 1.59%, respectively. At December 31, 2010, there was no accrued but unpaid interest on the LL&E Note.

Note 12. Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in cash distributions and to exercise other limited rights or privileges available to them under our Amended and Restated Agreement of Limited Partnership (as amended from time to time, the “Partnership Agreement”). We are managed by our general partner, DEP GP.

In accordance with our Partnership Agreement, we maintain separate tax-based capital accounts for our general partner and limited partners. The capital account provisions of the Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the GAAP-based equity amounts presented in our consolidated financial statements.

Earnings and cash distributions are allocated to holders of our common units in accordance with their respective ownership interests.

Class B Units

Our limited partners' equity account balance at December 31, 2008 reflected 37,333,887 Class B units issued to EPO in connection with the DEP II drop down transaction in December 2008. In February 2009, the Class B units were converted on a one-to-one basis into common units.

Registration Statements and Equity Offerings

We have a universal shelf registration statement on file with the SEC that allows us to issue up to an aggregate $1 billion in debt and equity securities for general partnership purposes. After taking into account previously issued securities under this registration statement, we can issue approximately $856.4 million of additional securities under this registration statement in the future.

In June 2009, we issued 8,000,000 common units to the public at an offering price of $16.00 per unit. We granted the underwriters of this offering a 30-day option to purchase up to 1,200,000 additional common units to cover over-allotments, which they exercised for 943,400 common units in July 2009. We generated net cash proceeds of approximately $137.4 million from this equity offering. The net proceeds were used to repurchase an equal number of our common units beneficially owned by EPO. The repurchased common units were subsequently cancelled. The repurchase of common units beneficially owned by EPO was reviewed and approved by each of the ACG Committees of our respective general partners. See Note 15 for information re garding our relationship with EPO.

In December 2009, we filed a registration statement with the SEC authorizing the issuance of up to 2,000,000 common units in connection with a distribution reinvestment plan ("DRIP"). The DRIP gives unitholders of record and beneficial owners of our common units the ability to increase the number of our common units they own through voluntarily reinvesting their quarterly cash distributions into the purchase of additional common units. Plan participants may purchase our common units at a discount ranging from 0% to 5% (currently set by us at 5%).

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 common units in connection with an employee unit purchase plan ("EUPP") and a long-term incentive plan (the "2010 Plan"). These plans became effective on February 11, 2010.

The following table reflects the number of common units we issued and net cash proceeds received in connection with the DRIP and EUPP during the year ended December 31, 2010:

	Number of Common Units Issued	Total Net Cash Proceeds
February DRIP	10,385	$ 0.2
May DRIP	11,521	0.3
May EUPP	11,017	0.3
August DRIP	9,856	0.2
August EUPP	6,962	0.2
November DRIP	9,529	0.3
November EUPP	6,553	0.2
Total 2010	65,823	$ 1.7

Unit History

The following table details changes in our outstanding units since January 1, 2008:

	Common Units	Class B Units	Treasury Units	Total Outstanding Units
Common units outstanding, January 1, 2008	20,301,571	--	--	20,301,571
Common units sold to EPO in connection with the DEP II drop down transaction in December 2008	41,529	--	--	41,529
Class B units issued in connection with the DEP II drop down transaction in December 2008	--	37,333,887	--	37,333,887
Common units outstanding, December 31, 2008	20,343,100	37,333,887	--	57,676,987
Conversion of Class B units to common units on February 1, 2009	37,333,887	(37,333,887)	--	--
June 2009 underwritten offering	8,000,000	--	--	8,000,000
Acquisition of common units from EPO in June 2009	(8,000,000)	--	8,000,000	--
Cancellation of treasury units in June 2009	--	--	(8,000,000)	(8,000,000)
Additional units issued in July 2009 in connection with June 2009 underwritten offering	943,400	--	--	943,400
Acquisition of common units from EPO in July 2009	(943,400)	--	943,400	--
Cancellation of treasury units in July 2009	--	--	(943,400)	(943,400)
Common units outstanding, December 31, 2009	57,676,987	--	--	57,676,987
Common units issued in connection with DRIP and EUPP during year	65,823	--	--	65,823
Common units issued to independent directors of DEP GP in connection with our 2010 Plan in February 2010	6,348	--	--	6,348
Common units outstanding, December 31, 2010	57,749,158	--	--	57,749,158

Cash Distributions

We are required to distribute our available cash (as defined in the Partnership Agreement) to our partners on a quarterly basis. Such distributions are not cumulative. In addition, we do not have a legal obligation to pay distributions at any set rate per unit. Our general partner has no incentive distribution rights.

The following table presents our declared quarterly cash distribution rates per common unit since the first quarter of 2009 and the related record and distribution payment dates. The quarterly cash distribution rates per common unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	Cash Distribution History		
	Per Unit	Record Date	Payment Date
2009			
1st Quarter	$ 0.4300	April 30, 2009	May 8, 2009
2nd Quarter	$ 0.4350	July 31, 2009	August 7, 2009
3rd Quarter	$ 0.4400	October 30, 2009	November 5, 2009
4th Quarter	$ 0.4450	January 29, 2010	February 5, 2010
2010			
1st Quarter	$ 0.4475	April 30, 2010	May 6, 2010
2nd Quarter	$ 0.4500	July 30, 2010	August 6, 2010
3rd Quarter	$ 0.4525	October 29, 2010	November 8, 2010
4th Quarter	$ 0.4550	January 31, 2011	February 7, 2011

Accumulated Other Comprehensive Income (Loss)

At December 31, 2009, accumulated other comprehensive loss was $5.4 million, which was attributable to changes in the value of interest rate derivative instruments. These derivative instruments expired in September 2010 and the related loss was reclassified out of accumulated other comprehensive loss to interest expense. See Note 6 for information regarding our use of derivative instruments.

Note 13. Noncontrolling Interest

We account for EPO's retained ownership interests in each of the DEP I and DEP II Midstream Businesses as a noncontrolling interest. Under this method of presentation, all revenues and expenses of these businesses are included in consolidated net income and EPO's share (as Parent) of the income of these businesses is deducted from consolidated net income to derive net income attributable to Duncan Energy Partners L.P. EPO's share of the net assets of the DEP I and DEP II Midstream Businesses is presented as noncontrolling interest in subsidiaries (a component of equity) on our Consolidated Balance Sheets. See Note 1 for a general description of the DEP I and DEP II Midstream Businesses.

DEP I Midstream Businesses – Parent

The DEP I Midstream Businesses allocate their net income (or loss) to EPO and us based on our respective sharing ratios, which are currently 34% for EPO and 66% for us. In deriving the net income (or loss) of Mont Belvieu Caverns to be allocated between EPO and us, certain special allocations are required: (i) EPO is allocated all operational measurement gains and losses and (ii) EPO is allocated 100% of the depreciation expense related to capital projects that it has fully funded.

Cash distributions by the DEP I Midstream Businesses to EPO and us are paid in accordance with each owner's respective sharing ratio. Likewise, cash contributions by EPO and us to the DEP I Midstream Businesses are made in accordance with the same sharing ratios; however, special funding arrangements exist with respect to certain capital projects under the terms of the limited liability company agreement of Mont Belvieu Caverns (the "Caverns LLC Agreement") and an Omnibus Agreement. See Note 15 for additional information regarding these related party agreements.

In accordance with the Omnibus Agreement, EPO agreed to fund all of the capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects that were underway at the time of our initial public offering in February 2007. EPO made aggregate cash contributions to South Texas NGL and Mont Belvieu Caverns of $1.4 million in connection with these capital projects during the year ended December 31, 2009. The majority of these contributions related to funding Phase II expansion costs of the South Texas NGL pipeline, which was completed in 2008. EPO will not receive an increased allocation of income or cash distributions as a result of these contributions to South Texas NGL and Mont Belvieu Caverns. There was no capital spending for the DEP I Midstream Businesses funded by EPO under the Omnibus Agreement during 2010.

Caverns LLC Agreement. EPO made cash contributions of $18.9 million and $16.6 million under the Caverns LLC Agreement during the years ended December 31, 2010 and 2009, respectively, to fund 100% of certain storage-related infrastructure projects sponsored by and for the benefit of EPO's NGL marketing activities. Duncan Energy Partners elected to not participate in these projects. Although Mont Belvieu Caverns owns the constructed assets, it is not expected to benefit economically from these specific capital improvements. As a result, EPO is not expected to receive an increased allocation of earnings or cash flows from Mont Belvieu Caverns as a result of these contributed capital expenditures. EPO wil l, however, be allocated the depreciation expense attributable to these projects. EPO's NGL marketing activities receive economic benefit directly from these expansion projects via increased marketing revenues. Additional contributions of approximately $12.6 million are expected from EPO to fund these specific projects in 2011.

Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances. The Caverns LLC Agreement allocates to EPO any items of income or loss relating to net operational measurement gains and losses, including amounts that Mont Belvieu Caverns may retain for handling losses. As such, EPO is required to contribute cash to Mont Belvieu Caverns for net operational measurement losses and is entitled to receive cash distributions from Mont Belvieu Caverns for net operational measurement gains. Operational measurement gains and losses are reflected in our consolidated operating costs and expenses and gross operating margin amounts; however, these gains and losses do not impact net income attributable to Duncan En ergy Partners since they are allocated to EPO through noncontrolling interest. In addition, operational measurement gains or losses do not have a significant impact on us with respect to the timing of our net cash flows provided by operating activities. Accordingly, we have not established a reserve for operational measurement losses on our balance sheet.

Amended Acadian LLC Agreement. On June 1, 2010, we entered into a second amended and restated limited liability company agreement for Acadian Gas (the "Amended Acadian LLC Agreement") with EPO. As part of this agreement, we and EPO agreed to fund the construction of the Haynesville Extension in accordance with our respective sharing ratios in Acadian Gas (i.e., 66% for us and 34% for EPO). EPO made cash contributions of $148.9 million to Acadian Gas under the Amended Acadian LLC Agreement in connection with the Haynesville Extension project during the year ended December 31, 2010. For additional information regarding the Amended Acadian LLC Ag reement, see "Significant Relationships and Agreements with EPO – Amended Acadian LLC Agreement" under Note 15.

The following table presents our calculation of "Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent" for the years ended December 31, 2010, 2009 and 2008:

	For the Year Ended December 31, 2010	2009	2008
Total net income of DEP I Midstream Businesses, after special allocations	$ 72.4	$ 68.0	$ 56.4
Multiplied by Parent 34% interest in net income	x 34%	x 34%	x 34%
Parent 34% interest in net income, after special allocations	24.6	23.1	19.2
Add (deduct) operational measurement gains (losses) allocated to Parent	9.5	(1.7)	(6.8)
Less depreciation expense related to capital projects funded entirely by and allocated to Parent	(6.4)	(6.1)	(1.0)
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	$ 27.7	$ 15.3	$ 11.4

The following table provides a reconciliation of the amounts presented as "Noncontrolling interest in subsidiaries – DEP I Midstream Businesses – Parent" on our Consolidated Balance Sheets at December 31, 2010 and 2009:

December 31, 2008 balance	$ 478.4
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	15.3
Contributions made by EPO to South Texas NGL and Mont Belvieu Caverns in connection with the following agreements:	
Caverns LLC Agreement	16.6
Omnibus Agreement	1.4
Other contributions made by EPO to the DEP I Midstream Businesses	0.9
Distributions paid to EPO by the DEP I Midstream Businesses	(25.3)
December 31, 2009 balance	487.3
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	27.7
Contributions made by EPO to Mont Belvieu Caverns in connection with the Caverns LLC Agreement	18.9
Contributions made by EPO to Acadian Gas in connection with the Amended Acadian LLC Agreement	148.9
Other contributions made by EPO to the DEP I Midstream Businesses	28.4
Distributions paid to EPO by the DEP I Midstream Businesses	(24.5)
December 31, 2010 balance	$ 686.7

For additional information regarding our agreements with EPO in connection with the DEP I drop down transaction, see Note 15.

DEP II Midstream Businesses – Parent

At the time of the DEP II drop down transaction, the total estimated fair value of the DEP II Midstream Businesses was approximately $3.2 billion. The total value of the consideration we provided to EPO in the DEP II drop down transaction was $730.0 million and represented, at the time of the transaction, the acquisition of controlling voting interests along with an initial 22.6% of the underlying equity in the DEP II Midstream Businesses. EPO retained the remaining 77.4% of equity. The 22.6% and 77.4% amounts are referred to as the "Percentage Interests," and represent each owner's initial relative economic investment in the DEP II Midstream Businesses at December 8, 2008.

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (the "Tier I distribution," based on our $730.0 million aggregate investment) and then to EPO (the "Tier II distribution"), in amounts sufficient to generate an annualized return to both owners based on their respective investments. Distributions in excess of these amounts (the "Tier III distributions") will be allocated 98% to EPO and 2% to us.

The initial annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, which was based on our estimated weighted-average cost of capital at December 8, 2008 plus 1.0%. The annualized return rate increases by 2.0% on January 1 of each year. As a result, the annualized return rate for 2010 was 12.087% and for 2011 will be 12.329%. If we participate in an expansion capital project involving the DEP II Midstream Businesses, we may request an incremental adjustment to the then-applicable annualized return rate to reflect our weighted-average cost of capital associated with such contribution.

The annualized return rate is applied to each party's aggregate investment (or "Distribution Base") in the DEP II Midstream Businesses. To the extent that we and/or EPO make capital contributions to fund expansion capital projects involving the DEP II Midstream Businesses, the Distribution Base of the contributing member will be increased by that member's capital contribution at the time such contribution is made. Our Distribution Base has remained at $730.0 million from December 8, 2008 through December 31, 2010. EPO's Distribution Base was $452.1 million, $817.9 million and $1.1 billion at December 8, 2008, December 31, 2009 and December 31, 2010, respectively. The increase in EPO's Distribution Base is the result of its decision to fund 100% of the expansion capital project costs of the DEP II Midstream Businesses since December 8, 2008. For the year ended December 31, 2010, EPO funded $320.2 million of expansion capital spending for the DEP II Midstream Businesses. This spending was primarily attributable to natural gas pipeline projects in the Barnett Shale resource basin (e.g., completion of the Trinity River Lateral in July 2010) and ongoing expansions of our pipeline network in the Eagle Ford Shale region. Although we have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, we may elect to invest in existing or future expansion projects at a later date.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity's Percentage Interest of 22.6% and 77.4%, respectively, and then in a manner that in part follows the cash distributions paid by (or contributions made to) each of the DEP II Midstream Business. Under our income sharing arrangement with EPO, we are allocated additional income (in excess of our Percentage Interest) to the extent that the cash distributions we receive (or contributions made) exceed the amount we would have been entitled to receive (or required to fund) based solely on our Percentage Interest. This additional earnings allocation to us reduces the amount of income allocated to EPO by an equal amount and may result in EPO being allocated a loss when we are allocated income. Our participation in the expected future increase in cash flow from such projects after EPO receives its full Tier II distribution is limited (beyond our annualized return amount) to 2% of such upside, with EPO receiving 98% of the benefit.

The following table presents the allocation of net income of the DEP II Midstream Businesses for the 24-day period extending from December 8, 2008 to December 31, 2008.

	EPO		DEP
Total net income of DEP II Midstream Businesses		$ 0.5	$ 0.5
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		0.4	0.1
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 5.4		
Multiplied by 22.6% Percentage Interest of Duncan Energy Partners	22.6%		
Duncan Energy Partners' Percentage Interest in the total cash distributions paid by the DEP II Midstream Businesses with respect to period	1.2		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(5.6)	(4.4)	4.4
Net loss attributable to EPO as noncontrolling interest		$ (4.0)	
Net income attributable to Duncan Energy Partners			$ 4.5

The following table presents the allocation of net loss of the DEP II Midstream Businesses for the year ended December 31, 2009:

		EPO	DEP
Total net loss of DEP II Midstream Businesses		$ (0.5)	$ (0.5)
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		(0.4)	(0.1)
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 116.3		
Multiplied by 22.6% Percentage Interest of Duncan Energy Partners	22.6%		
Duncan Energy Partners' Percentage Interest in the total cash distributions paid by the DEP II Midstream Businesses with respect to period	26.3		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(86.5)	(60.2)	60.2
Net loss attributable to EPO as noncontrolling interest		$ (60.6)	
Net income attributable to Duncan Energy Partners			$ 60.1

The following table presents the allocation of net loss of the DEP II Midstream Businesses for the year ended December 31, 2010:

		EPO	DEP
Total net loss of DEP II Midstream Businesses		$ (8.4)	$ (8.4)
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		(6.5)	(1.9)
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 134.3		
Multiplied by 22.6% Percentage Interest of Duncan Energy Partners	22.6%		
Duncan Energy Partners' Percentage Interest in the total cash distributions paid by the DEP II Midstream Businesses with respect to period	30.3		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(88.2)	(57.9)	57.9
Net loss attributable to EPO as noncontrolling interest		$ (64.4)	
Net income attributable to Duncan Energy Partners			$ 56.0

The DEP II Midstream Businesses distributed an aggregate of $134.3 million and $116.3 million for the years ended December 31, 2010 and 2009, respectively. Of these amounts, EPO received $46.1 million and $29.8 million for the years ended December 31, 2010 and 2009, respectively.

The $88.2 million (or, approximately, $22.1 million each quarter) received by us with respect to 2010 represents the annualized return rate for 2010 of 12.087% multiplied by our Distribution Base of $730.0 million. As a result, we received our expected Tier I distributions for the period. Based on EPO's Distribution Base throughout 2010, it was entitled to $121.9 million of Tier II distributions, of which it received only $46.1 million. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to 2010.

The following table provides a reconciliation of the amounts presented as "Noncontrolling interest in subsidiaries – DEP II Midstream Businesses – Parent" on our Consolidated Balance Sheets at December 31, 2010 and 2009:

December 31, 2008 balance	$ 2,613.0
Allocated loss from DEP II Midstream Businesses to EPO as Parent	(60.6)
Contributions by EPO in connection with expansion cash calls	344.5
Distributions to noncontrolling interest of subsidiary operating cash flows	(31.8)
Other general cash contributions from noncontrolling interest	23.1
December 31, 2009 balance	2,888.2
Allocated loss from DEP II Midstream Businesses to EPO as Parent	(64.4)
Contributions by EPO in connection with expansion cash calls	320.2
Distributions to noncontrolling interest of subsidiary operating cash flows	(47.7)
Return of contributions to EPO in connection with the transfer of an expansion capital project to Mont Belvieu Caverns	(25.4)
Other general cash contributions from noncontrolling interest	1.6
December 31, 2010 balance	$ 3,072.5

For additional information regarding our agreements with EPO in connection with the DEP II drop down transaction, see "Relationship with EPO – Company and Limited Partnership Agreements – DEP II Midstream Businesses" under Note 15.

Note 14. Business Segments

We have three reportable business segments: (i) Natural Gas Pipelines & Services; (ii) NGL Pipelines & Services and (iii) Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

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) gains and losses from asset sales and related transactions and (iv) 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 any intersegment and intrasegment 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 transacti ons, 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.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions.

We include equity earnings from Evangeline in our measurement of segment gross operating margin and operating income. This investee is important to the operations of Acadian Gas and is within the same industry as our consolidated operations; thus we believe the presentation of equity earnings from Evangeline as a component of gross operating margin and operating income is appropriate.

Segment assets consist of property, plant and equipment, our investment in Evangeline, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until they are placed in service. Intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For Year Ended December 31,		
	2010	2009	2008
Revenues	$ 1,115.1	$ 979.3	$ 1,598.1
Less: Operating costs and expenses	(1,030.4)	(908.3)	(1,512.8)
Add: Equity in income of Evangeline	0.8	1.1	0.9
Depreciation, amortization and accretion in operating costs and expenses (1)	201.0	186.3	167.3
Non-cash asset impairment charges included in operating costs and expenses (2)	5.2	4.2	--
Loss (gain) from asset sales and related transactions in operating costs and expenses (3)	7.9	(0.5)	(0.5)
Total segment gross operating margin	$ 299.6	$ 262.1	$ 253.0

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on the Statements of Consolidated Cash Flows.
(2) See Note 6 for additional information regarding non-cash asset impairment charges.
(3) Amount presented for the twelve months ended December 31, 2010 includes a $9.1 million loss related to the disposal of a non-strategic pipeline segment owned by Enterprise Texas.

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 indicated:

	For the Year Ended December 31,		
	2010	2009	2008
Total segment gross operating margin	$ 299.6	$ 262.1	$ 253.0
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(201.0)	(186.3)	(167.3)
Non-cash asset impairment charges included in operating costs and expenses	(5.2)	(4.2)	--
Gain (loss) from asset sales and related transactions in operating costs and expenses	(7.9)	0.5	0.5
General and administrative costs	(20.0)	(11.2)	(18.3)
Operating income	65.5	60.9	67.9
Other expense, net	(12.1)	(13.8)	(11.5)
Income before provision for income taxes	$ 53.4	$ 47.1	$ 56.4

Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments				
	Natural Gas Pipelines & Services	NGL Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:					
Year ended December 31, 2010	$ 408.3	$ 115.4	$ 13.6	$ --	$ 537.3
Year ended December 31, 2009	382.2	96.2	13.6	--	492.0
Year ended December 31, 2008	761.8	80.4	14.2	--	856.4
Revenues from related parties:					
Year ended December 31, 2010	430.3	147.5	--	--	577.8
Year ended December 31, 2009	356.5	130.8	--	--	487.3
Year ended December 31, 2008	593.5	148.2	--	--	741.7
Total revenues:					
Year ended December 31, 2010	838.6	262.9	13.6	--	1,115.1
Year ended December 31, 2009	738.7	227.0	13.6	--	979.3
Year ended December 31, 2008	1,355.3	228.6	14.2	--	1,598.1
Equity in income of Evangeline:					
Year ended December 31, 2010	0.8	--	--	--	0.8
Year ended December 31, 2009	1.1	--	--	--	1.1
Year ended December 31, 2008	0.9	--	--	--	0.9
Gross operating margin by individual business segment and in total:					
Year ended December 31, 2010	167.2	122.8	9.6	--	299.6
Year ended December 31, 2009	148.2	103.4	10.5	--	262.1
Year ended December 31, 2008	159.0	82.9	11.1	--	253.0
Segment assets:					
At December 31, 2010	3,527.6	996.1	80.4	807.4	5,411.5
At December 31, 2009	3,340.8	946.1	83.3	233.7	4,603.9
At December 31, 2008	2,909.8	936.5	86.6	459.0	4,391.9
Property, plant and equipment:					
At December 31, 2010	3,506.1	968.3	80.4	807.4	5,362.2
At December 31, 2009	3,318.8	913.8	83.4	233.6	4,549.6
At December 31, 2008	2,887.5	897.1	86.6	459.0	4,330.2
Investment in Evangeline: (see Note 9)					
At December 31, 2010	6.4	--	--	--	6.4
At December 31, 2009	5.6	--	--	--	5.6
At December 31, 2008	4.5	--	--	--	4.5
Intangible assets:					
At December 31, 2010	10.7	27.3	--	--	38.0
At December 31, 2009	12.0	31.8	--	--	43.8
At December 31, 2008	13.4	38.9	--	--	52.3
Goodwill:					
At December 31, 2010	4.4	0.5	--	--	4.9
At December 31, 2009	4.4	0.5	--	--	4.9
At December 31, 2008	4.4	0.5	--	--	4.9

Our consolidated revenues were earned in the United States. Our operations are located in Texas and Louisiana. During 2010 and 2009, EPO, a related party, was our largest customer and accounted for 34.5% and 33.8% of our consolidated revenues, respectively. Evangeline, another related party, was our largest customer during 2008 and accounted for 22.7% of our consolidated revenues. During 2010, 2009 and 2008, our largest non-affiliated customer was Exxon Mobil, which accounted for 7.4%, 7.5% and 10.0%, respectively, of our consolidated revenues.

The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and costs and expenses for the periods noted:

	For the Year Ended December 31,		
	2010	2009	2008
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 536.5	$ 460.2	$ 1,100.2
Natural gas transportation services	286.1	263.2	246.7
Natural gas storage services	16.0	15.3	8.4
Total	$ 838.6	$ 738.7	$ 1,355.3
NGL Pipelines & Services:			
Sales of NGLs	$ 45.9	$ 35.0	$ 47.9
Sales of other products	18.2	11.3	15.0
NGL and related product storage services	120.5	104.9	87.4
NGL fractionation services	30.8	29.5	32.4
NGL transportation services	45.4	43.8	43.6
Other services	2.1	2.5	2.3
Total	$ 262.9	$ 227.0	$ 228.6
Petrochemical Services:			
Propylene transportation services	$ 13.6	$ 13.6	$ 14.2
Total consolidated revenues	$ 1,115.1	$ 979.3	$ 1,598.1
Consolidated cost and expenses:			
Operating costs and expenses:			
Cost of sales (natural gas and NGLs)	$ 573.6	$ 479.7	$ 1,123.9
Depreciation, amortization and accretion	201.0	186.3	167.4
Loss (gain) from asset sales and related transactions	7.9	(0.5)	(0.5)
Other operating expenses	247.9	242.8	222.0
General and administrative costs	20.0	11.2	18.3
Total consolidated costs and expenses	$ 1,050.4	$ 919.5	$ 1,531.1

Changes in our revenues and operating costs and expenses year-to-year are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of natural gas and NGLs; however, these higher commodity prices also increase the associated cost of sales as purchase costs rise.

Note 15. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Year Ended December 31, 2010	2009	2008
Revenues:			
Revenues from EPO:			
Sales of natural gas	$ 139.2	$ 141.9	$ 177.3
Natural gas transportation services	113.8	56.4	51.5
Natural gas storage services	1.5	2.6	0.9
Sales of NGLs	44.6	33.7	52.9
NGL and petrochemical storage services	39.0	36.2	35.2
NGL fractionation services	30.8	32.0	29.7
NGL transportation services	32.7	28.6	30.4
Sales of natural gas – Evangeline	174.5	155.5	362.9
Natural gas transportation services – Energy Transfer Equity	1.3	0.1	0.9
NGL and petrochemical storage services – Energy Transfer Equity	0.4	0.3	--
Total related party revenues	$ 577.8	$ 487.3	$ 741.7
Operating costs and expenses:			
EPCO administrative services agreement	$ 87.2	$ 85.8	$ 72.1
Expenses with EPO:			
Purchases of natural gas	68.9	52.1	229.9
Operational measurement losses (gains)	(9.5)	1.7	6.8
Other expenses with EPO	16.8	16.4	18.4
Purchases of natural gas – Nautilus	0.2	1.7	10.3
Expenses with Energy Transfer Equity:			
Purchases of natural gas	11.0	5.7	7.3
Operating cost reimbursements for shared facilities	(4.1)	(3.4)	(2.8)
Other expenses with Energy Transfer Equity (1)	(0.5)	(0.7)	3.1
Total related party operating costs and expenses	$ 170.0	$ 159.3	$ 345.1
General and administrative costs:			
EPCO administrative services agreement	$ 17.4	$ 10.9	$ 15.7
Other related party general and administrative costs	0.1	--	(0.8)
Total related party general and administrative costs	$ 17.5	$ 10.9	$ 14.9
Other income (expense) transactions:			
Interest expense - Loan Agreement with EPO	$ (0.9)	$ --	$ --

The following table summarizes our related party accounts receivable and accounts payable amounts at the dates indicated:

	December 31, 2010	December 31, 2009
Accounts receivable – related parties		
EPO and affiliates (1)	$ 19.5	$ 54.3
Energy Transfer Equity and affiliates	1.6	0.2
Total	$ 21.1	$ 54.5
Accounts payable – related parties		
EPO and affiliates	$ 13.6	$ 5.5
EPCO and affiliates	13.2	8.1
Total	$ 26.8	$ 13.6

(1) In December 2009, EPO borrowed $45.6 million under a Master Intercompany Loan Agreement, which was subsequently repaid in January 2010. See "Significant Relationships and Agreements with EPO" within this Note 15 for more information.

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.

Relationship with EPO

One of our primary business purposes is to support the growth objectives of EPO and other affiliates of EPCO that are under common control. Our assets are integral to EPO's midstream energy operations. We believe that the operational significance of our assets to EPO, as well as the alignment of our economic interests in these assets with EPO, will result in a collaborative effort to promote their operational efficiency and maximize value. In addition, we believe our relationship with EPO provides us with a distinct benefit in the identification and execution of potential future acquisitions that are not otherwise taken by Enterprise.

At December 31, 2010, EPO beneficially owned approximately 58.5% of our common units and 100% of our general partner. See Note 21 for information regarding Enterprise's February 22, 2011 offer to acquire all of our outstanding publicly-held common units.

EPO was the sponsor of the DEP I and DEP II drop down transactions and owns noncontrolling economic interests in the DEP I and DEP II Midstream Businesses. For a description of EPO's noncontrolling interest in the income and net assets of the DEP I and DEP II Midstream Businesses, see Note 13. EPO may contribute or sell other equity interests or assets to us in the future; however, EPO has no obligation or commitment to make such contributions or sales to us, nor do we have any obligation to accept such contributions or make such acquisitions.

EPO has continuing involvement with our subsidiaries, including the following: (i) it utilizes our storage services to support its operations at Mont Belvieu, Texas; (ii) it buys from, and sells to, us natural gas in connection with its normal business activities; and (iii) it is currently the sole shipper on an NGL pipeline system located in South Texas that we own.

Master Intercompany Loan Agreement. On December 31, 2009, we and EPO entered into a master intercompany loan agreement with the DEP I and DEP II Midstream Businesses. This agreement will be used from time to time to facilitate cash management efforts in connection with the DEP I and DEP II Midstream Businesses. On December 31, 2009, we and EPO borrowed $1.3 million and $45.6 million, respectively, under the agreement at a market rate of interest. EPO's intercompany borrowing is a component of "Accounts receivable – related parties" on our Consolidated Balance Sheets. These amounts were subsequently repaid on January 4, 2010.&# 160; The interest rate applicable to these short-term borrowings was 0.73% per annum. Amounts borrowed by us and the related interest eliminate in consolidation. Neither we nor EPO borrowed any additional amounts under this agreement during the year ended December 31, 2010.

Loan Agreement with EPO. In June 2010, we entered into a loan agreement with EPO. This loan agreement was terminated in October 2010. See Note 11 for additional information regarding this related party loan agreement.

Omnibus Agreement. On December 8, 2008, we entered into an amended and restated Omnibus Agreement (the "Omnibus Agreement") with EPO that addressed various matters. The key provisions of this agreement at December 31, 2010 are summarized as follows:

§ EPO agreed to fund 100% of the post-February 5, 2007 capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects under construction at the time of our initial public offering;

§ EPO agreed to fund 100% of post-December 8, 2008 capital expenditures to complete the Sherman Extension natural gas pipeline (a component of our Texas Intrastate System);

- § EPO was granted a right of first refusal in our current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business;

- § EPO was granted a preemptive right with respect to any equity securities issued by certain of our subsidiaries, other than those that may be issued as consideration in an acquisition or in connection with a loan or debt financing;

- § Neither EPO nor any of its affiliates are restricted under the Omnibus Agreement from competing against us;

- § We and EPO agreed to negotiate in good faith any necessary amendments to the partnership or company agreements of the DEP II Midstream Businesses when either party believes that business circumstances have changed; and

- § Our general partner’s Audit, Conflicts and Governance Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

Mont Belvieu Caverns’ LLC Agreement. The Caverns LLC Agreement states that if Duncan Energy Partners elects to not participate in the expansion projects of Mont Belvieu Caverns, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO, by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66% share of these expansion projects from EPO within 90 days of such projects being placed in service. Effective November 2008, the Caverns LLC Agreement provides for EPO to prospectively receive a special allocation of 100% of the depreciation expense related to expansion projects that it has fully funded.

The Caverns LLC Agreement also requires the allocation to EPO of operational measurement gains and losses. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances.

For information regarding capital expenditures funded 100% by EPO under the Caverns LLC Agreement as well as operational measurement gains and losses allocated to EPO, see “Noncontrolling Interest – DEP I Midstream Businesses – Parent” under Note 13.

Company and Limited Partnership Agreements – DEP II Midstream Businesses. On December 8, 2008, the DEP II Midstream Businesses amended and restated their governing documents in connection with the DEP II drop down transaction. Collectively, these amended and restated agreements provided for (i) the acquisition by us of a 66% general partner interest in Enterprise GC, a 51% general partner interest in Enterprise Intrastate and a 51% member interest in Enterprise Texas; (ii) the payment of cash distributions by the DEP II Midstream Businesses to us and EPO in accordance with a waterfall approach (see Note 13); (iii) the funding of operating cash flow deficits of the DEP II Midst ream Businesses in accordance with each owner’s respective partner or member interest; and (iv) the election by either owner to participate in the funding of expansion capital projects of the DEP II Midstream Businesses.

Since December 8, 2008, we have elected to not participate in the funding of expansion capital projects of the DEP II Midstream Businesses and, as a result, EPO has funded 100% of such expenditures. If we later elect to participate in any expansion projects, then we will be required to make a capital contribution for our share of such project costs. For information regarding capital expenditures funded 100% by EPO under the DEP II agreements, see “Noncontrolling Interest – DEP II Midstream Businesses – Parent” under Note 13.

Amended Acadian LLC Agreement. On June 1, 2010, we entered into the Amended Acadian LLC Agreement with EPO. As part of this agreement, we and EPO agreed to fund the construction of the

Haynesville Extension in accordance with our respective sharing ratios in Acadian Gas (i.e., 66% for us and 34% for EPO). The total budgeted cost of the Haynesville Extension is approximately $1.56 billion (including capitalized interest); therefore, we estimate that our share of such costs will approximate $1.03 billion. In order to fund our capital spending requirements under the Haynesville Extension project, we entered into new long-term senior unsecured credit facilities in October 2010 having an aggregate borrowing capacity of $1.25 billion (see Note 11).

As part of the agreement, we reimbursed EPO for 66% of certain construction expenses it paid related to the Haynesville Extension project from the inception of the project through the date of the agreement (plus interest). In June 2010, Acadian Gas acquired a purchase order, originally held by EPO for a previous project, for approximately 175 miles of pipe with a value of $167.4 million. This pipe is being used in the construction of the Haynesville Extension. Acadian Gas reimbursed EPO approximately $90.9 million for its prior payments on this order of pipe, of which our 66% share was approximately $60.0 million.

The Amended Acadian LLC Agreement also includes provisions related to future expansion projects of Acadian Gas other than the Haynesville Extension. When such projects are presented for funding, Acadian Gas will request additional capital contributions from us and EPO based on our respective sharing ratios. Acadian Gas will provide us and EPO with written notice of the due date for our initial contributions and we and EPO will have 20 days to give a written reply as to whether we elect to participate in the expansion project. We or EPO may propose to contribute an amount less than that requested by Acadian Gas, at which time we and EPO will decide whether to proceed with the expansion project.

Relationship with EPCO

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA. We, Enterprise and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel.

§ We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

§ EPCO will allow us to participate as named insureds in its overall insurance program, with the associated premiums and other costs being allocated to us.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including compensation of its employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation o f legal or accounting salaries based on estimates of time spent on each entity’s business and affairs). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods indicated:

	For Year Ended December 31,		
	2010	2009	2008
Operating costs and expenses	$ 87.2	$ 85.8	$ 72.1
General and administrative expenses	17.4	10.9	15.7
Total costs and expenses	$ 104.6	$ 96.7	$ 87.8

Since the vast majority of expenses charged to us under the ASA are on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

The ASA also addresses potential conflicts that may arise among Enterprise and Enterprise GP, Duncan Energy Partners and DEP GP, and the EPCO Group with respect to business opportunities (as defined within the ASA) with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise, Duncan Energy Partners and their respective general partners.

Relationship with Evangeline

Acadian Gas sold $174.5 million, $155.5 million and $362.9 million of natural gas to Evangeline during the years ended December 31, 2010, 2009 and 2008, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract was 36.8 BBtus for each of the years ended December 31, 2010 and 2009 and 36.9 BBtus for the year ended December 31, 2008. For the year ended December 31, 2008, Evangeline was our largest customer and accounted for 22.7% of our consolidated revenues. For the years ended December 31, 2010 and 2009, EPO was our largest customer (see Note 14).

Relationship with Energy Transfer Equity

Enterprise has a noncontrolling ownership interest in Energy Transfer Equity that is accounted for using the equity method. As a result of common control of Enterprise and us, Energy Transfer Equity is considered a related party to us. Our revenues from Energy Transfer Equity are attributable to natural gas transportation services and NGL and petrochemical storage services. Our related party expenses with Energy Transfer Equity primarily include natural gas purchases for pipeline imbalances, reimbursements of operating costs for shared facilities and the lease of a pipeline in South Texas.

Note 16. Earnings Per Unit

Basic and diluted earnings per unit is computed by dividing net income or loss attributable to our limited partners by the weighted-average number of distribution-bearing common and Class B units (see Note 12) outstanding during a period. We have no dilutive securities.

The amount of net income or loss allocated to limited partner interests is net of our general partner's share of such earnings. The following table presents the allocation of net income to DEP GP for the periods indicated:

	For the Year Ended December 31,		
	2010	2009	2008
Total net income attributable to Duncan Energy Partners L.P.	$ 90.1	$ 91.1	$ 47.9
Less: Income allocated to former owners of the DEP II Midstream Businesses	--	--	(19.6)
Net income allocated to Duncan Energy Partners L.P. for purposes of determining earnings per unit	90.1	91.1	28.3
Multiplied by DEP GP ownership interest (weighted-average for period)	0.7%	0.7%	1.7%
Net income allocation to DEP GP	$ 0.6	$ 0.6	$ 0.5

From the closing of our initial public offering on February 5, 2007 through December 7, 2008, DEP GP maintained a 2% general partner interest in us. In connection with the DEP II dropdown transaction on December 8, 2008, DEP GP elected to forego making a cash contribution to us to maintain its 2.0% general partner interest. As a result, DEP GP's general partner interest was reduced to 0.7% beginning December 8, 2008.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Year Ended December 31,		
	2010	2009	2008
Net income allocation to Duncan Energy Partners L.P.	$ 90.1	$ 91.1	$ 28.3
Less: Income allocation to DEP GP	0.6	0.6	0.5
Net income allocation to limited partners	$ 89.5	$ 90.5	$ 27.8
Basic and diluted earnings per unit:			
Net income allocation to limited partners (numerator)	$ 89.5	$ 90.5	$ 27.8
Weighted-average units outstanding: (denominator)			
Common units	57.7	54.5	20.3
Class B units	--	3.2	2.5
Total units	57.7	57.7	22.8
Basic and diluted earnings per unit	$ 1.55	$ 1.57	$ 1.22

Note 17. Commitments and Contingencies

Litigation

As part of our normal business activities, we or our unconsolidated affiliate 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. See Note 18 for information regarding our insurance program. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

Our reserve for litigation contingencies totaled $6.8 million at December 31, 2010 and relates to a contractual dispute involving our South Texas NGL pipeline system that began prior to its acquisition from a third party in September 2004. Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of such matters involves substantial uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional reserves for litigation contingencies. In an effort to mitigate potential adverse consequences of litigation, we may settle legal proceedings out of court.

Redelivery Commitments

We transport and store natural gas and NGLs and store petrochemical products for third parties under various contracts. These volumes are: (i) accrued as product payables on our Consolidated Balance Sheets; (ii) in transit for delivery to our customers; or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our NGL and petrochemical product storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2010, NGL and petrochemical products aggregating 15.3 MMBbls were due to be redelivered to their owners along with 4.6 trillion Btus of natural gas. See Note 2 for more in formation regarding accrued product payables.

Regulatory Matters

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 (e.g., California and New Mexico) 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.

The U.S. Environmental Protection Agency ("EPA") has taken action under the federal Clean Air Act ("CAA") to regulate greenhouse gas 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, including certain onshore oil and natural gas production activities, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, 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 EPA's Prevention o f Significant Deterioration 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.

These or other federal, regional and state measures could increase the operating and compliance costs of our pipelines, 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. In addition, 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. All this, or any future such developments, may have an adverse effect on our business, financial position re sults of operations and cash flows.

Any of these climate change regulatory and legislative initiatives or litigation developments could have a material adverse effect on our business, financial position and results of operations.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2010. A description of each type of contractual obligation follows (dollars in millions):

	Payment or Settlement due by Period						
Contractual Obligations (1)	**Total**	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**
Scheduled maturities of debt obligations	$ 788.3	$ 282.3	$ --	$ 506.0	$ --	$ --	$ --
Estimated cash interest payments (2)	$ 34.6	$ 14.1	$ 11.2	$ 9.3	$ --	$ --	$ --
Operating lease obligations	$ 107.2	$ 8.9	$ 8.7	$ 7.4	$ 6.6	$ 6.3	$ 69.3
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 294.9	$ 172.5	$ 122.4	$ --	$ --	$ --	$ --
Other	$ *	$ *	$ *	$ --	$ --	$ --	$ --
Underlying major volume commitments:							
Natural gas (in BBtus)	69,959	40,926	29,033	--	--	--	--
Capital expenditure commitments (3)	$ 285.3	$ 285.3	$ --	$ --	$ --	$ --	$ --

* Amounts are negligible.

(1) The contractual obligations presented in this table reflect 100% of our subsidiaries' obligations even though we own less than a 100% equity interest in our operating subsidiaries.

(2) Our estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2010. In calculating these amounts, we applied the weighted-average variable interest rates paid during 2010 associated with such debt.

(3) Capital expenditure commitments are reflected on a consolidated basis before contributions, if any, from noncontrolling interest (e.g., contributions required in connection with the Caverns LLC Agreement and Amended Acadian LLC Agreement (see Note 15)).

Scheduled Maturities of Debt Obligations. We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods presented. See Note 11 for additional information regarding our consolidated debt obligations.

Operating lease obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements consist of the lease of underground storage caverns for natural gas and NGLs (primarily our lease for the Wilson natural gas storage facility, which is integral to the operations of our Texas Intrastate System) and land held pursuant to right-of-way agreements. The current term on the Wilson facility lease expires in 2028. In accordance with this lease, we have the option to purchase the Wilson facility at either December 31, 2024 for $61.0 million or January 25, 2028 for $55.0 million. In addition, the lessor, at its election, may cause us to purchase the Wilson facility for $65.0 million at the end of any calendar quarter extending through December 31, 2023. Ou r pipeline operations have entered into leases for land held pursuant to right-of-way agreements. Our significant right-of-way agreements have original terms that range from five to 50 years and include renewal options that could extend the agreements for up to an additional 25 years. Our rental payments are generally at fixed rates, as specified in the individual contracts, and may be subject to escalation provisions for inflation and other market-determined factors.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during the years ended December 31, 2010, 2009 or 2008. Consolidated costs and expenses include lease expense amounts of $13.6 million, $11.0 million and $11.2 million for the years ended December 31, 2010, 2009 and 2008 , respectively.

Purchase Obligations. We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

§ We have long and short-term product purchase obligations for natural gas with third-party suppliers. Our most significant product purchase obligation is a commitment that Acadian Gas has for the purchase of natural gas in Louisiana (see Note 9) that expires in January 2013. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price in each agreement at December 31, 2010 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. & #160;At December 31, 2010, we do not have any significant product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

§ We also have short-term payment obligations relating to our capital spending program. These commitments represent unconditional payment obligations for services to be rendered or products to be delivered in connection with our capital projects. At December 31, 2010, we had approximately $285.3 million of consolidated capital expenditure commitments outstanding, which primarily relate to the Haynesville Extension project (Acadian Gas) and Eagle Ford Shale projects (Texas Intrastate System). See Note 15 for information regarding capital project funding arrangements with EPO.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally may make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2010, we had no contingent claims against such parties and claims against us were approximately $1.9 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters have not been reflected in our consolidated financial statements.

Note 18. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry. We are engaged in the business of NGL transportation, fractionation and marketing; storage of NGL, petrochemical and refined products; transportation of petrochemical products; and the gathering, transportation, marketing and storage of natural gas. A reduction in demand for natural gas, NGL and other hydrocarbon products by the petrochemical, refining or heating industries, whether because of general economic conditions; reduced demand by consumers for the end products made using NGLs; increased competition from other products due to pricing differences; adverse weather conditions; government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline ; or other reasons, could adversely affect our financial position, results of operations and cash flows.

Credit Risk Due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults. See Note 14 for information regarding our largest customer.

Counterparty Risk with Respect to Derivative Instruments

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral nor do we anticipate nonperformance by our counterparties.

Insurance-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damage or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, the proceeds of any insurance recovery may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our cons olidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

EPCO's deductible for onshore physical damage from windstorms is currently $30.0 million per storm. EPCO's onshore insurance program currently provides $141.3 million of coverage per occurrence for named windstorm events. With respect to offshore Gulf of Mexico assets (e.g., the near-shore natural gas gathering pipelines of our TPC Offshore system, which is a component of our Texas Intrastate System), the deductible for windstorm damage is $75.0 million per storm. EPCO's insurance program for offshore Gulf of Mexico assets currently provides $124.5 million of coverage in the aggregate. In addition, at EPCO's election, we now have access to an additional $17.5 million of coverage for either onshore or offshore windstorm-related damage claims. For non-windsto rm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence.

With respect to onshore assets, we have business interruption coverage in connection with windstorms. We do not have any business interruption coverage for our offshore Gulf of Mexico assets when the outage is due to a windstorm. However, we have business interruption coverage for both onshore and offshore assets in connection with non-windstorm events. Assets covered by business interruption insurance must be out-of-service in excess of 60 days before any allowed losses from business interruption will be covered.

Interest Rate Risk

We are exposed to changes in interest rates charged on our variable rate debt obligations. Our $175 million of floating-to-fixed interest rate swaps, which partially hedged our exposure to changes in variable interest rates on our Revolving Credit Facility, expired in September 2010. In October 2010, we executed new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion. See Note 11 for additional information.

Note 19. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating accounts and cash payments for interest and income taxes for the periods indicated.

	For the Year Ended December 31,		
	2010	2009	2008
Decrease (increase) in:			
Accounts receivable - trade	$ 11.7	$ 39.6	$ 5.0
Accounts receivable - related parties	(14.2)	(9.9)	1.2
Gas imbalance receivables	(1.7)	25.9	(1.4)
Inventories	4.7	17.5	(6.0)
Prepaid and other current assets	(3.6)	(5.3)	1.6
Increase (decrease) in:			
Accounts payable – trade	9.5	(1.7)	(5.9)
Accounts payable – related parties	5.4	(39.9)	13.5
Accrued product payables	1.3	(45.4)	(8.7)
Accrued taxes	1.8	0.9	6.4
Other current liabilities	24.6	(16.4)	5.1
Other long-term liabilities	--	(0.2)	(12.6)
Net effect of changes in operating accounts	$ 39.5	$ (34.9)	$ (1.8)
Cash payments for interest, net of $3.2, $0.3 and $0.3 capitalized in 2010, 2009 and 2008, respectively	$ 20.6	$ 13.8	$ 11.5
Cash payments for income taxes	$ 0.6	$ 1.0	$ 0.2

We incurred liabilities for construction in progress that had not been paid at December 31, 2010, 2009 and 2008 of $76.9 million, $41.8 million and $30.5 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and producer well tie-ins. These amounts are included under the caption "Contributions in aid of construction costs" on the Statements of Consolidated Cash Flows.

See Note 13 for information regarding cash amounts attributable to noncontrolling interests.

The following table presents the components of depreciation, amortization and accretion for the periods indicated:

	For Year Ended December 31,		
	2010	2009	2008
Depreciation, amortization and accretion expense:			
DEP I Midstream Businesses	$ 42.9	$ 38.7	$ 34.3
DEP II Midstream Businesses	161.6	147.4	133.1
Other	1.2	2.2	0.4
Total	$ 205.7	$ 188.3	$ 167.8

Note 20. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial for the periods indicated:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2010:				
Revenues	$ 290.6	$ 265.2	$ 283.7	$ 275.6
Operating income	18.7	15.3	9.1	22.4
Net loss attributable to noncontrolling interest	5.5	11.5	14.9	4.8
Net income attributable to Duncan Energy Partners L.P.	21.2	23.3	20.6	25.0
Allocation of net income attributable to Duncan Energy Partners L.P.:				
Limited partners	21.0	23.2	20.4	24.9
General partner	0.2	0.1	0.2	0.1
Earnings per unit (basic and diluted)	0.37	0.40	0.36	0.43
For the Year Ended December 31, 2009:				
Revenues	$ 256.8	$ 226.7	$ 244.6	$ 251.2
Operating income	14.8	8.7	21.1	16.3
Net loss attributable to noncontrolling interest	8.9	18.7	7.0	10.7
Net income attributable to Duncan Energy Partners L.P.	19.9	23.2	24.8	23.2
Allocation of net income attributable to Duncan Energy Partners L.P.:				
Limited partners	19.8	23.0	24.6	23.1
General partner	0.1	0.2	0.2	0.1
Earnings per unit (basic and diluted)	0.34	0.40	0.43	0.40

Note 21. Subsequent Events

Incident at Mont Belvieu Storage Facility

On February 8, 2011, a fire occurred at our Mont Belvieu, Texas underground 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. The Mo nt Belvieu underground storage facility is owned by Mont Belvieu Caverns, which is owned 66% by Duncan Energy Partners and 34% by EPO. 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.

Enterprise Offers to Acquire Publicly-Held Common Units of 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 our 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 of our outstanding publicly-held common units as part of a transaction that would be structured as a merger between us 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 our common units and the closing price of Enterprise 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.

DUNCAN ENERGY PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	For the Years Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
Consolidated net income	$ 53.4	$ 45.8	$ 55.3	$ 23.6	$ 51.7
Add: Provision for income taxes	--	1.3	1.1	4.2	1.7
Less: Equity in income of Evangeline	(0.8)	(1.1)	(0.9)	(0.2)	(1.0)
Consolidated pre-tax income before equity earnings from Evangeline	52.6	46.0	55.5	27.6	52.4
Add: Fixed charges	19.9	17.6	15.3	14.5	3.2
Amortization of capitalized interest	4.2	4.0	1.0	0.6	--
Subtotal	76.7	67.6	71.8	42.7	55.6
Less: Interest capitalized	(3.2)	(0.3)	(0.3)	(2.6)	--
Net loss (income) attributable to noncontrolling interest:					
DEP I Midstream Businesses - Parent	(27.7)	(15.3)	(11.4)	(20.0)	--
DEP II Midstream Businesses - Parent	64.4	60.6	4.0	--	--
Total earnings	$ 110.2	$ 112.6	$ 64.1	$ 20.1	$ 55.6
Fixed charges:					
Interest expense	$ 12.1	$ 14.0	$ 11.4	$ 8.6	$ --
Capitalized interest	3.2	0.3	0.3	2.6	--
Interest portion of rental expense	4.6	3.3	3.6	3.3	3.2
Total	$ 19.9	$ 17.6	$ 15.3	$ 14.5	$ 3.2
Ratio of earnings to fixed assets	5.5x	6.4x	4.2x	1.4x	17.4x

These computations take into account our consolidated operations and the distributed income from our equity method investee. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income from continuing operations before adjustment for income or loss from our equity investee;
- fixed charges;
- amortization of capitalized interest;
- distributed income of our equity investee; and
- our share of pre-tax losses of our equity investee for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- the noncontrolling interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of the interest within rental expenses; and preference security dividend requirements of consolidated subsidiaries.

Our ratio is significantly higher for the year ended December 31, 2006 because we did not have any interest expense, capitalized interest expense or noncontrolling interest in income of subsidiaries.

Exhibit 21.1

LIST OF SUBSIDIARIES
DUNCAN ENERGY PARTNERS L.P.
as of February 1, 2011

Name of Subsidiary	Jurisdiction of Formation	Direct and Indirect Effective Ownership
Acadian Gas, LLC	Delaware	66%
Acadian Gas Pipeline System	Texas	100%
Calcasieu Gas Gathering System	Texas	100%
Cypress Gas Marketing, LLC	Delaware	100%
Cypress Gas Pipeline, LLC	Delaware	100%
DEP Offshore Port System, LLC	Texas	100%
DEP OLPGP, LLC	Delaware	100%
DEP Operating Partnership, L.P.	Delaware	100%
Enterprise Big Thicket Pipeline System LLC	Texas	100%
Enterprise GC, L.P.	Delaware	66%
Enterprise Holding III, LLC	Delaware	100%
Enterprise Intrastate L.P.	Delaware	51%
Enterprise Lou-Tex Propylene Pipeline L.P.	Delaware	66%
Enterprise Texas Pipeline LLC	Texas	51% (1)
Evangeline Gulf Coast Gas, LLC	Delaware	100%
MCN Acadian Gas Pipeline, LLC	Delaware	100%
MCN Pelican Interstate Gas, LLC	Delaware	100%
Mont Belvieu Caverns, LLC	Delaware	66%
Neches Pipeline System	Texas	100%
Pontchartrain Natural Gas System	Texas	100%
Sabine Propylene Pipeline L.P.	Texas	66%
South Texas NGL Pipelines, LLC	Delaware	66%
Tejas-Magnolia Energy, LLC	Delaware	100%
TXO-Acadian Gas Pipeline, LLC	Delaware	100%

(1) Reflects a 51% voting membership interest. The economic interest of this membership interest includes tiered preference distributions and priority returns.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement Nos. 333-149583 and 333-163842 of Duncan Energy Partners L.P. on Form S-3; and (ii) Registration Statement No. 333-164852 of Duncan Energy Partners L.P. on Form S-8 of our reports dated March 1, 2011, relating to the consolidated financial statements of Duncan Energy Partners L.P. and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph indicating the financial statements of the Company were prepared from the separate records maintained by Enterprise Products Partners L.P. or affiliates and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity), and the effectiveness of Duncan Energy Partners L .P. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Duncan Energy Partners L.P. for the year ended December 31, 2010.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2011

EXHIBIT 31.1

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this annual report on Form 10-K of Duncan Energy Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2011

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Executive Officer of DEP Holdings, LLC, the General Partner of Duncan Energy Partners L.P.

EXHIBIT 31.2

CERTIFICATIONS

I, Bryan F. Bulawa, certify that:

1. I have reviewed this annual report on Form 10-K of Duncan Energy Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2011

/s/ Bryan F. Bulawa

Name: Bryan F. Bulawa
Title: Chief Financial Officer of DEP Holdings, LLC, the General Partner of Duncan Energy Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

**CERTIFICATION OF W. RANDALL FOWLER, CHIEF EXECUTIVE OFFICER
OF DEP HOLDINGS, LLC, THE GENERAL PARTNER OF
DUNCAN ENERGY PARTNERS L.P.**

In connection with this annual report of Duncan Energy Partners L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Executive Officer of DEP Holdings, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Executive Officer of DEP Holdings, LLC,
the General Partner of Duncan Energy Partners L.P.

Date: March 1, 2011

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

**CERTIFICATION OF BRYAN F. BULAWA, CHIEF FINANCIAL OFFICER
OF DEP HOLDINGS, LLC, THE GENERAL PARTNER OF
DUNCAN ENERGY PARTNERS L.P.**

In connection with this annual report of Duncan Energy Partners L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bryan F. Bulawa, Chief Financial Officer of DEP Holdings, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Bryan F. Bulawa

Name:	Bryan F. Bulawa
Title:	Chief Financial Officer of DEP Holdings, LLC, the General Partner of Duncan Energy Partners L.P.

Date: March 1, 2011