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, 2009

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 the Duncan Energy Partners L.P.'s (or "DEP's") common units held by non-affiliates at June 30, 2009, was approximately $361.6 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 L. Duncan and Enterprise Products Operating LLC. There were 57,676,987 common units of DEP outstanding at February 1, 2010.

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. References to “DEP OLP” mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners through which Duncan Energy Partners conducts substantially all of its business.

References to “Enterprise Products Partners” mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise Products Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “EPD.” References to “EPGP” mean Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners. References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business, and its consolidated subsidiaries. EPO beneficially owns 100% of DEP GP and is a significant owner of our common units. Enterprise Products Partners consolidates our financial statements with those of its own.

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 Products Partners. On October 26, 2009, Enterprise Products Partners completed the mergers with TEPPCO and TEPPCO GP. On October 27, 2009, Enterprise Products Partners’ TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

References to “Enterprise GP Holdings” mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol “EPE.” Enterprise GP Holdings owns EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC (“EPE Holdings”), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan.

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”). 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.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETP.”

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”). Our ownership interests in the DEP II Midstream Businesses are held by Enterprise Holding III, L.L.C., which is a wholly owned subsidiary of DEP OLP. Ownership interests in the DEP II Midstream Businesses that were retained by EPO are held by its wholly owned subsidiary, Enterprise GTM Holdings L.P.

Within the context of our financial information, references to "former owners" mean EPO's ownership interests in the DEP I and DEP II Midstream Businesses prior to the effective date of the related drop down transactions.

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 "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. We, Enterprise Products Partners, EPO, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. (EPE Unit III), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which are privately held affiliates of EPCO.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2009 ("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 statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

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." Duncan Energy Partners was formed in September 2006 and did not own any assets prior to February 5, 2007, which was the date it completed its initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. The business purpose of Duncan Energy Partners 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. Duncan Energy Partners is engaged in the business of: (i) natural gas liquids ("NGLs") transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical 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.

Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, at December 31, 2009. EPO owned approximately 58.6% of our common units and 100% of DEP GP at December 31, 2009. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. EPCO provides all of our employees and certain administrative services to us.

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 for additional information regarding our 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. 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 $300 million unsecured revolving credit facility (the "Revolving Credit Facility") and $260.6 million of the $290.5 million of net proceeds from our initial public offering. 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 two 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 1.0 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 263-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% general partner interest in Enterprise GC, (ii) a 51% general partner interest in Enterprise Intrastate and (iii) a 51% 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 $300.0 million senior unsecured term loan agreement (the "Term Loan Agreement") and $0.5 million of net proceeds from an equity offering to EPO. The market value 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, Shoup and Armstrong, located in south Texas; (ii) a 1,020-mile NGL pipeline system located in south Texas; and (iii) 1,112 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 190-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 6,560-mile Enterprise Texas natural gas pipeline system, which includes the Sherman Extension, and leases the Wilson natural gas storage facility. The Enterprise Texas system, along with the Waha, TPC Offshore and Channel pipeline systems, comprise our Texas Intrastate System.

Generally, 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 (based on an initial defined investment of $730.0 million) and then to EPO in amounts sufficient to generate an aggregate initial annualized return on their respective investments of 11.85%. Effective January 1, 2010, the annualized return increased by 2.0% to 12.087%. Distributions in excess of these amounts will be distributed 98% to EPO and 2% to us. Income and loss of the DEP II Midstream Businesses are first allocated to EPO and us based on each entity's percentage interest of 77.4% and 22.6%, respectively, and then in a manner that in part follows the cash distributions.

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

Basis of Financial Statement 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.

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 within this annual report. Such financial information is incorporated by reference into this Item 1 and 2 discussion.

Significant Recent Developments

Haynesville Extension

In October 2009, we and EPO announced plans to extend our Acadian Gas System into the rapidly growing Haynesville Shale natural gas supply basin in northwest Louisiana (the “Haynesville Extension”). In November 2009, we received additional firm transportation commitments from shippers, which will support an increase to the capacity of the Haynesville Extension pipeline project. The transportation capacity of our 249-mile Haynesville Extension pipeline has been increased from 1.4 Bcf/d, as originally designed, to 2.1 Bcf/d of natural gas and will extend from the Haynesville region to interconnects in central Louisiana with the existing Acadian Gas System. The pipeline is expected to be placed into service during the third quarter of 2011 and be part of our Natural Gas Pipelines & Services business segment.

The Haynesville Extension will provide producers in the Haynesville Shale natural gas supply basin with much needed takeaway capacity, including access to more than 150 end-use markets along the Mississippi River corridor between Baton Rouge and New Orleans. In addition, shippers will be able to access our Napoleonville salt dome storage cavern and have the ability to make physical deliveries into the Henry Hub and benefit from additional pricing points. The Haynesville Extension will also allow shippers to reach nine interstate pipeline systems.

We currently own a 66% equity interest in the entities that own the Acadian Gas System, with EPO owning the remaining 34% equity interest. We and EPO are in discussions as to the funding and related aspects of the Haynesville Extension project.

Service Begins on Sherman Extension Pipeline

In late February 2009, we and EPO announced that construction had been completed on the 173-mile Sherman Extension expansion of our Texas Intrastate System, which extends through the heart of the prolific Barnett Shale natural gas production basin of north Texas. The completion of the Sherman Extension adds 1.2 Bcf/d of incremental natural gas takeaway capacity from the region, while providing producers in the Barnett Shale, and as far away as the Waha area of west Texas, with greater flexibility to reach the most attractive natural gas markets. The Texas Intrastate System is part of our Natural Gas Pipelines & Services business segment through interconnections with pipelines that serve the Midwest and Northeast regions of the United States.

For additional information regarding these and other recent developments during 2009, see “Significant Recent Developments” included under Item 7 of this annual report, which 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 33.8% of our consolidated revenues for 2009. Evangeline, another related party, was our largest customer during 2008 and 2007 and accounted for 22.7% and 21.7% of our consolidated revenues each year, respectively. 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. Related party revenues from Evangeline are attributable to the sale of natural gas and are presented in our Natural Gas Pipelines & Services business segment. Sales to EPO totaled $331.4 million for the year ended December 31, 2009. Sales to Evangeline totaled $362.9 million and $264.2 million for the years ended December 31 2008 and 2007, respectively.

Our largest non-affiliated customer is Exxon Mobil Corporation and its affiliates (collectively, "Exxon Mobil"), which accounted for 7.5%, 10.0% and 7.6% of our consolidated revenues in 2009, 2008 and 2007, respectively. The majority of our revenues from Exxon Mobil is derived from the sale and transportation of natural gas and is presented in our Natural Gas Pipelines & Services business segment. Sales to Exxon Mobil totaled $73.4 million, $159.2 million and $93.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

/d= per day
BBtus= billion British thermal units
Bcf= billion cubic feet
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.

Natural Gas Pipelines & Services

Our Natural Gas Pipelines & Services business 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. 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 natural gas supply basins and from offshore developments in the Gulf of Mexico through connections with offshore pipelines. We also recently announced our intention to expand our Acadian Gas System to provide services to producers in the Haynesville Shale natural gas supply basin in northwest Louisiana. Our natural gas pipelines receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers or to other 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 of operations for our natural gas pipelines and related marketing activities are generally dependent upon the volume of natural gas transported and/or sold and amounts charged to customers.

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. 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 for sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal modes of operation. The ability of underground salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates 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 storage 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 facilities. Our natural gas marketing activities compete primarily with other natural gas pipeline companies and their marketing affiliates and financial institutions with trading platforms. Competition in the natural gas marketing business is based primarily on quality of customer service, competitive pricing and proximity to customers and other market hubs.

Properties. The following table summarizes the significant assets included in our Natural Gas Pipelines & Services business segment at February 1, 2010:

Description of Asset	Location	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Working Capacity (Bcf)
Natural gas pipelines:				
Texas Intrastate System	Texas	8,051	6,640	
Acadian Gas System	Louisiana	1,041	1,149	
Big Thicket Gathering System (1)	Texas	262	60	
Canales Gathering System	Texas	32	75	
Total miles		9,386		
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 62.5%, 68.3% and 63.3% during the years ended December 31, 2009, 2008 and 2007, respectively.

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 6,560-mile Enterprise Texas pipeline system, the 641-mile Channel pipeline system, the 660-mile Waha gathering system and the 190-mile TPC Offshore gathering system. The Enterprise Texas pipeline system includes a 263-mile pipeline we lease from an affiliate of ETP. The leased Wilson natural gas storage facility, located in Wharton County, Texas, is an integral part of the Texas Intrastate System. Collectively, the Texas Intrastate System serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

The 173-mile Sherman Extension pipeline, which is part of our Texas Intrastate System, was completed in February 2009 and is capable of transporting up to 1.2 Bcf/d of natural gas from the prolific Barnett Shale production 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 late 2008, we began design of the 40-mile Trinity River Lateral, which is expected to be completed during the second quarter of 2010. The Trinity River Lateral will be capable of transporting up to 1.0 Bcf/d of natural gas and will provide producers in the Barnett Shale production basin with additional takeaway capacity. We are also constructing a new storage cavern adjacent to the leased Wilson natural gas storage facility that is expected to be completed in 2010. When completed, this new cavern is expected to provide us with an additional 5.0 Bcf of useable natural gas storage capacity.

As a result of the DEP II drop down transaction, we own a 51% equity interest in the entity that owns the Enterprise Texas and Channel pipeline systems and leases 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 leased Acadian natural gas storage facility at Napoleonville, Louisiana is an integral part of the Acadian Gas System. 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 build the Haynesville Extension. As currently designed, our Haynesville Extension pipeline will have the capacity to transport up to 2.1 Bcf/d of natural gas from the Haynesville region through a 249-mile pipeline that will connect with our existing Acadian Gas System. The pipeline is expected to be placed into service during the third quarter of 2011.

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, including a 49.51% interest in the Evangeline pipeline, discussed below.

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 $155.5 million, $362.9 million and $264.2 million for the years ended December 31, 2009, 2008 and 2007, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract averaged approximately 50 BBtus/d during each of the years ended December 31, 2009, 2008 and 2007, respectively.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our NGL and related product storage facility located at Mont Belvieu, Texas and our South Texas NGL Pipeline System that connects our Mont Belvieu storage complex to midstream energy infrastructure located in south Texas. In addition, this segment includes two NGL fractionators located in south Texas and the results of NGL marketing activities related to our Big Thicket Gathering System.

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 and petrochemical storage facilities receive, store and deliver NGLs and petrochemical 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 and petrochemical 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 the Rocky Mountain and Midwest regions via EPO’s Seminole pipeline, to Louisiana via EPO’s Lou-Tex NGL pipeline and to 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 packaging, 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.

Under our NGL and petrochemical storage agreements, we charge customers monthly storage reservation fees to reserve storage capacity in our underground caverns. Our customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge customers throughput fees based on volumes placed into and withdrawn from storage. Lastly, brine production revenues are derived from 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 for 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 withdrawn 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 gains and losses associated with our Mont Belvieu storage complex as a component of operating costs and expenses. However, these operational measurement gains and losses should not affect our net income attributable to Duncan Energy Partners 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 net operational measurement losses of $1.7 million and $6.8 million for the years ended December 31, 2009 and 2008, respectively, and a net operational measurement gain of $4.5 million for the year ended December 31, 2007, which were 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 to, and collect purity NGL products from, petrochemical plants and refineries. Revenues from our NGL pipeline transportation agreements are generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. 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 of our Big Thicket Gathering System generate revenues from the sale and delivery of NGLs obtained 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 processing plants. Revenues from our NGL fractionators are generally based on fee-based arrangements for our NGL fractionation services. These arrangements typically include a base-processing fee (usually stated in cents per gallon) that is contractually subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. Purity NGL products from the Shoup and Armstrong fractionators are transported to Mont Belvieu, Texas using our South Texas NGL System.

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, which is believed to cover more than 10 million acres in southern Texas. Certain natural gas production from this region is rich in NGLs that must be removed before the natural gas can meet quality specifications to be transported in downstream natural gas pipelines. In the mid-Gulf Coast region, rich Wilcox gas is found at depths in the 10,000 to 15,000 feet range. Shale gas in these areas may also have high NGL content. We expect that ongoing natural gas exploration and production activities will result in new volumes that will mitigate the effects of normal depletion rates of existing resource basins.

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 weather 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 the fees we charge our storage customers are competitive with those charged by other 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 pipelines and fractionators are 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, 2010:

Description of Asset	Location	Length (Miles)	Useable Storage Capacity (MMBbls)	Total Plant Capacity (MBPD)
NGL pipelines:				
South Texas NGL Pipeline System	Texas	1,317		
NGL and petrochemical storage facilities:				
Mont Belvieu Storage (34 caverns) (1)	Texas		103.5	
Almeda (6 caverns) (1, 2)	Texas		13.4	
Markham (2 caverns) (1, 2)	Texas		4.3	
Total useable capacity			121.2	
NGL fractionation facilities:				
Shoup	Texas			69
Armstrong	Texas			13
Total plant capacities				82

(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 South Texas NGL Pipeline System 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 South Texas NGL Pipeline System in terms of average throughput. Total average throughput volume for this pipeline was 109 MBPD, 126 MBPD and 124 MBPD during the years ended December 31, 2009, 2008 and 2007, respectively.

On a weighted-average basis, aggregate utilization rates for our NGL fractionation plants were approximately 86.8%, 84.3% and 82.8% during the years ended December 31, 2009, 2008 and 2007, 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 and Almeda NGL storage facilities.

§ The *Mont Belvieu Storage* complex consists of three interconnected underground storage facilities: Mont Belvieu East, Mont Belvieu West and Mont Belvieu North. The Mont Belvieu East 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 Mont Belvieu West 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. The Mont Belvieu North 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.

Our storage customers include a broad range of NGL and petrochemical 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 20.5% of our segment revenues for the year ended December 31, 2009, were affiliates of Exxon Mobil, Dow Chemical Company and Chevron Corporation.

We also provide underground storage services to EPO, which accounted for 34.0% of our Mont Belvieu storage revenues for the year ended December 31, 2009.

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 Pipeline System* consists of (i) approximately 380 miles of 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 and (ii) intrastate NGL pipelines aggregating 937 miles that deliver NGLs from the Shoup and Armstrong fractionators to our Mont Belvieu storage complex and to other customers along the upper Texas Gulf Coast. The leased Markham and Almeda NGL storage facilities are integral components of the South Texas NGL System.

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.

A major customer of our South Texas NGL Pipeline System and Shoup and Armstrong NGL fractionators is EPO. EPO accounted for 82.6% of revenues generated by these assets during the year ended December 31, 2009.

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 Pipeline System and Shoup and Armstrong fractionators. 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 263-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. Department 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 which 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 30 MBPD, 35 MBPD and 37 MBPD during the years ended December 31, 2009, 2008 and 2007, 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 knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license. We believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Capital Spending

For a discussion of our capital spending programs, see “Liquidity and Capital Resources” included under Item 7 of this annual report.

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 nondiscriminatory. 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 distribution 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, and to make certain rate and other filings and reports in compliance 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.

In September 2007, the FERC approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Texas Pipeline. In June and July 2008, we filed to amend our Statement of Operating Conditions ("SOC") for our transportation and storage services, respectively. In September 2008, we submitted to the FERC a new proposed Section 311 rate for service on our Sherman Extension pipeline. On November 23, 2009, we filed an uncontested settlement agreement, which, if approved, would resolve the Sherman Extension rate issues. The other issues related to the SOC are reserved under the settlement agreement for a decision by the FERC based on the pleadings. Under the settlement agreement that resulted from the September 2007 proceeding, we are required to file another rate petition on or before April 2010 to justify our current rates or establish new rates for the NGPA Section 311 service on the remainder of the system. The FERC has not acted upon the settlement agreement. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Texas.

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 December 8, 2009, the FERC issued an order extending its review period to encourage settlement discussions. Settlement negotiations are on-going.

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 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, are required to begin posting the information by June 30, 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 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"); and analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our financial position, results of operations and cash flows. If an accidental 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 jointly and severally 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 clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows. Below is a discussion of the material environmental laws and regulations that relate to our business.

Air Emissions

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

Our permits and related compliance under the CAA, as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas, may require our operations to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some of our facilities are included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. 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.

In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide and methane, are contributing to the warming of the Earth’s atmosphere and other climatic changes, the U.S. Congress has been actively considering legislation to reduce such emissions. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (“ACESA”), which would establish an economy-wide cap-and-trade program intended to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane that may contribute to warming of the Earth’s atmosphere and other climatic changes. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, the Environmental Protection Agency (“EPA”) would issue a capped and steadily declining number of tradable emissions allowances to major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The costs of these allowances would be expected to escalate significantly over time. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and 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.

In addition, on December 7, 2009, the EPA announced its finding that emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its endangerment finding that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010.

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. 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.

Even if such legislation is not adopted at the national level, more than one-third of the states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. Although most of the state-level initiatives have to date focused on large sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to greenhouse gas emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial position and results of operations.

Other Potential Impacts of Climate Change

Over the last hundred years or so, certain instrumental temperature records have evidenced a general increase in global mean temperature. As a result, certain public advocacy groups attribute this rise to a phenomenon termed “global warming.” Proponents of this theory argue that man-made greenhouse gases have produced observable changes in the environment such as shrinkage of the Arctic ice caps, releases of terrestrial carbon from permafrost regions and increases in sea level. In addition, these individuals believe that global warming will result in a continued increase in global average temperatures over the course of this century, with a probable increase in the frequency of extreme weather events, and changes in rainfall patterns. Based on computer models promoted by these groups, certain areas of the globe might benefit from such changes, while other areas would experience costs. Severe global climate change could even result in reduced diversity of ecosystems and the extinction of certain species.

There is considerable debate in public and private forums as to whether global warming is actually occurring and, if it is, its consequences. 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 may be at increased risk due to flooding or more frequent and severe weather events. Also, a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases may reduce volumes available to us for fractionation, transportation, marketing and storage. Unfortunately, there is currently no public consensus regarding global warming, and the scientific community is divided on the subject. We are providing this disclosure regarding the potential physical effects of global warming based on publicly available information and opinions on the matter. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming.

Water

The CWA and comparable state laws impose strict controls on the discharge of oil and its derivatives into navigable 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 navigable waters. The EPA has also adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate. These permits may require us to monitor and sample the storm water run-off. The CWA and regulations implemented thereunder further prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. We believe that our costs of compliance with these CWA requirements will not have a material adverse effect on our operations.

The primary federal law for oil spill liability is the OPA, which addresses three principal areas of oil pollution: prevention, containment and cleanup and liability. OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, 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 as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, but such costs are site specific, and there is no assurance that the effect will not be material in the aggregate.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal RCRA and comparable state statutes, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste. Amendments to RCRA required the EPA to promulgate regulations banning the land disposal of all hazardous wastes unless the wastes meet certain treatment standards or the land-disposal method meets certain waste containment criteria. In the past, although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and other materials may have been disposed of or released. In the future, we may be required to remove or remediate these materials.

Environmental Remediation

The CERCLA, also known as "Superfund," imposes liability, 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, these persons 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 also authorizes 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 generate wastes that may fall within CERCLA's definition of a "hazardous substance." In the event a disposal facility previously used by us requires clean up in the future, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

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. 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.

Risk Management Plans

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

Safety Matters

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

We 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 EPA 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.

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 ("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, 2009, 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 operating 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. From time-to-time, 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. The Company does not intend to incorporate the information on our website in 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 Inherent in 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 2008, ranged from a high of $13.58 per MMBtu to a low of $5.29 per MMBtu. In 2009, the NYMEX daily settlement price for natural gas ranged from a high of $6.07 per MMBtu to a low of $2.51 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.

§ *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 pipelines 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 reached record levels during 2008, but current prices have declined in recent months. 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 South Texas NGL Pipeline System 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 pipelines companies in the areas they serve. We also compete with trucks, railroads 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. 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, 2009, we had $175.0 million of indebtedness outstanding under our revolving credit agreement, which matures in February 2011, with the ability to borrow up to an additional $121.7 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, which matures in December 2011. The terms of these facilities were negotiated prior to the financial crisis of 2008 and are more favorable than terms currently available in the financial markets. Our level of indebtedness could have important consequences to us, 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. As of December 31, 2009, our consolidated variable rate debt was effectively $282.3 million. The remainder of our outstanding debt on this date reflects $175.0 million in notional amount of floating-to-fixed interest rate swaps, which expire in September 2010. 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, thereby providing more stable cash flow. We regularly 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 on 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 ERISA.

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 associated with pipeline integrity testing and any repairs found to be necessary as a result of such testing. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in "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 partner owns incentive distribution rights, including Enterprise Products Partners. In addition, we may elect to participate in capital projects with Enterprise Products Partners, whereby our expected return on investment may be lower than that of Enterprise Products Partners, 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 and Enterprise GP Holdings. 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 (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to maintain and increase over time distributions 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 Products Partners, 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 Products Partners and Enterprise GP Holdings to service such indebtedness. Any distributions by Enterprise Products Partners and Enterprise GP Holdings 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 or 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 Gulf Coast region makes them particularly vulnerable to hurricane 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, accordingly, 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 significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. 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. 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 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 materially affect our results of operations, cash flows and financial position.

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, impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

We will 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 regulation is one area of potential future environmental law development. Studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” may be contributing to warming of the Earth’s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

On December 7, 2009, the EPA announced its findings that emissions of greenhouse gases present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of

CAA regulations in anticipation of finalizing its endangerment findings that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final CAA rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. These regulations will require reporting for some of our facilities, and additional EPA regulations expected to be adopted in 2010 will require other of our facilities to report their greenhouse gas emissions, possibly beginning in 2012 for emissions occurring in 2011.

Also, on June 26, 2009, the U.S. House of Representatives passed ACESA, which would establish an economy-wide cap-and-trade program intended to reduce U.S. emissions of "greenhouse gases." ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The cost of these allowances would be expected to escalate significantly over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system.

Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, the adoption and implementation of any CAA regulations, and any future federal, state or local laws or implementing regulations that may be adopted to address greenhouse gas emissions, could require us to incur increased operating costs and could adversely affect demand for the natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services. The effect on our operations could include increased costs to operate and maintain our facilities, install new emission controls on our facilities, measure and report our emissions, 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. 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.

Global warming, if occurring, may also impact our operations directly, including increased maintenance costs for our facilities, increased flooding and severe weather risks for our facilities that are located in low-lying areas and coastal regions, and reduced demand for hydrocarbon products that may reduce demand and volumes of the products that we fractionate, transport, market and store.

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 our unitholders.

The workplaces associated with our pipelines are subject to the requirements of the 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 have a material adverse effect on our business, financial position, results of operations and ability to make distributions to our unitholders.

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, 2009, 2008 and 2007, EPO and its affiliates accounted for approximately 33.8%, 23.6% and 16.1% 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 a segment of our South Texas NGL Pipeline System 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 required 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 unitholders.

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 key members of our senior management team, including Dan L. Duncan, 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 Inherent in an Investment in Us

Enterprise Products Partners 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 Products Partners 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 Products Partners, 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, Enterprise Products Partners and its general partner, or Enterprise GP Holdings 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. If EPO abandons the business opportunity for itself or for us, then Enterprise GP Holdings will have the second right to pursue such opportunity. If any business opportunity to acquire general partner interests and other related equity securities in a publicly traded partnership is presented, then Enterprise GP Holdings will have the right to pursue such opportunity before EPO is given the opportunity to pursue it for itself or to direct it 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 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, 2009, EPO indirectly owned a 0.7% general partner interest and beneficially owned approximately 58.6% 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 Products Partners 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 Products Partners and its affiliates, including our general partner, on the one hand, and us and our unitholders, 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 Products Partners, 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, Enterprise Products Partners, and Enterprise GP Holdings 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 Products Partners and Enterprise GP Holdings 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, Enterprise Products Partners and Enterprise GP Holdings 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 Products Partners and Enterprise GP Holdings, 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 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 Products Partners. 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, Enterprise GP Holdings and its general partner and Enterprise Products Partners 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 in the fourth quarter of 2008 and during 2009. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet capital commitments and achieve the flexibility needed to react to changing economic and business conditions. The credit crisis could have a negative impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, demand for our services and products depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Also, a decrease in demand for NGLs by the petrochemical and refining industries due to a decrease in demand for their products as a result of general economic conditions would likely impact demand for our services and products. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

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 from 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, 2010, affiliates of Enterprise Products Partners own our general partner and approximately 58.6% 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 audit, conflicts and governance 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, 2010, affiliates of Enterprise Products Partners, which owns our general partner, owned approximately 58.6% 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. For example, all cash flows from Evangeline are currently used to service its debt.

Affiliates of Enterprise Products Partners 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 liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

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

Our general partner 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 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 benefit of an investment in our common units depends largely 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 income at the corporate tax rate, which is currently a maximum of 35%. Distributions to our unitholders could generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits could flow through to unitholders. Because a tax could be imposed upon us as a corporation, our cash available for distribution to our common unitholders could be substantially reduced. Thus, treatment of us as a corporation could result in a material reduction in the after-tax return to our common 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 common unitholders could 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 U.S. 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 U.S. federal income tax laws and interpretations thereof 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 U.S. 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. For example, in response to recent public offerings of interests in the management operations of private equity funds and hedge funds, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704 of the Internal Revenue Code and changing the treatment of certain types of income earned from profits or “carried” interests. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Although we are unable to predict whether any of these changes or other proposals will ultimately be enacted and, if so, whether any such changes would be applied retroactively, the enactment of any such changes could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our 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 are 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 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.

Common 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 by us, which decreases the unitholder's tax basis in a 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.

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.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts 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 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 result in a decrease in the value of our common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could decrease 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 unitholder's tax returns.

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

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. 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 responsibility of each unitholder to file its own federal, state and local tax returns.

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

We will be considered to have terminated 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 termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

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) adjustment 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, he 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 he may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Item 1B. *Unresolved Staff Comments*.

None.

Item 3. *Legal Proceedings.*

On occasion we are, or our unconsolidated affiliate is, named as a defendant in legal proceedings relating to our normal business operations, including 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 financial position, results of operations or cash flows. For detailed information regarding our legal proceedings, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which is incorporated by reference into this Item 3.

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Item 4. [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, 2010, there were approximately 40 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
2008					
1st Quarter	$ 23.65	$ 18.29	$ 0.4100	April 30, 2008	May 7, 2008
2nd Quarter	21.29	18.04	0.4200	July 31, 2008	August 7, 2008
3rd Quarter	18.96	14.91	0.4200	October 31, 2008	November 12, 2008
4th Quarter	16.99	9.68	0.4275	January 30, 2009	February 9, 2009
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

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.

On December 8, 2008, we issued 37,333,887 Class B units to EPO in connection with the DEP II drop down transaction. On February 9, 2009, the Class B units received a cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008, which represented the regular quarterly distribution pro-rated for the 24-day period from December 8, 2008, the closing date of the DEP II drop down transaction, to December 31, 2008. These units automatically converted on a one-for-one basis to common units on February 1, 2009.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2009 that have not been previously reported.

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2009, there were no effective long-term incentive plans of EPCO under which our common units are authorized for issuance. However, 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 on December 30, 2009 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 Item 9B "Other Information" and Note 5 of the Notes to Consolidated Financial Statements included in Item 8 of this annual report.

Issuer Purchases of Equity Securities

In June 2009, we completed a common unit offering of 8,000,000 units at an average price paid per unit of $15.36 that generated net proceeds of approximately $122.9 million after underwriting discounts and other expenses. In July 2009, the underwriters of this offering exercised a portion of their 30-day option to purchase an additional 943,400 common units at an average price per unit of $15.36, which generated approximately $14.5 million of additional net proceeds. The total net 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.

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 within this annual report. Information regarding our consolidated results of operations and liquidity and capital resources can be found under Item 7 within this annual report. As presented in the table, amounts are in millions (except per unit data).

	For the Year Ended December 31,				
	2009	2008	2007	2006	2005
Operating Results Data:					
Revenues	$ 979.3	$ 1,598.1	$ 1,220.3	$ 1,263.0	$ 1,257.8
Net income	45.8	55.3	23.6	51.7	30.1
Net loss (income) attributable to noncontrolling interest (1)	45.3	(7.4)	(20.0)	--	--
Net income attributable to Duncan Energy Partners	91.1	47.9	3.6	51.7	30.1
Allocation of net income attributable to Duncan Energy Partners L.P.:					
Limited partners of Duncan Energy Partners	$ 90.5	$ 27.8	$ 18.8	n/a	n/a
General partner of Duncan Energy Partners	0.6	0.5	0.4	n/a	n/a
Former owner of DEP II Midstream Businesses	n/a	19.6	(20.6)	(3.7)	(9.0)
Former owner of DEP I Midstream Businesses	n/a	n/a	5.0	55.3	39.1
Basic and diluted earnings per unit	$ 1.57	$ 1.22	$ 0.93	n/a	n/a
Cash distributions per common unit (2)	$ 1.75	$ 1.68	$ 1.46	n/a	n/a
Financial position data:					
Total assets (3)	$ 4,770.8	$ 4,594.7	$ 3,983.3	$ 3,798.4	$ 3,688.9
Long-term debt (4)	457.3	484.3	200.0	n/a	n/a
Former owner's equity in DEP II Midstream Businesses (5)	n/a	n/a	2,880.1	2,853.8	2,903.6
Former owner's equity in DEP I Midstream Businesses (5)	n/a	n/a	n/a	725.8	527.8
Equity (6)	4,136.9	3,844.2	669.9	n/a	n/a
Total common units outstanding (7)	57.7	57.7	20.3	n/a	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 Revolving Credit Facility and Term Loan Agreement, as applicable, for the periods in which Duncan Energy Partners had borrowings outstanding under each agreement.

(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 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, 2009, 2008 and 2007.

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes included under Item 8 within 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, 2009 and through the date of this filing.
- § General Outlook for 2010.
- § Results of Operations – Discusses material year-to-year variances in our Statements of Consolidated Operations.

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- § 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. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." Duncan Energy Partners was formed in September 2006 and did not own any assets prior to February 5, 2007, which was the date it completed its initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. The business purpose of Duncan Energy Partners 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. Duncan Energy Partners is engaged in the business of: (i) NGLs transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas.

Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, at December 31, 2009. EPO beneficially owned approximately 58.6% of our common units and 100% of DEP GP at December 31, 2009. 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.

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

DEP I Drop Down

On February 5, 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 within 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% general partner interest in Enterprise GC, (ii) a 51% general partner interest in Enterprise Intrastate and (iii) a 51% 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 units at the time of issuance was approximately $449.5 million. See Item 1 and 2 within this annual report for a description of the assets and operations of the DEP II Midstream Businesses.

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 Financial Statement 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 fiscal 2007 represent the eleven-month period from our initial public offering (effective February 1, 2007) through December 31, 2007. Amounts presented for the DEP II Midstream Businesses for fiscal 2008 represent the period from December 8, 2008 to December 31, 2008.

	Twelve Months		Eleven Months
	Ended December 31,		
	2009	2008	2007
	(dollars in millions)		
Selected income statement information:			
Equity in income - DEP I Midstream Businesses	$ 44.9	$ 37.2	$ 30.0
Equity in income - DEP II Midstream Businesses	$ 60.1	$ 4.5	$ --
General and administrative costs	$ 0.4	$ 1.4	$ 1.5
Interest expense	$ 13.5	$ 12.0	$ 9.3
Net income attributable to Duncan Energy Partners L.P.	$ 91.1	$ 28.3	$ 19.2
Selected balance sheet information at each period end:			
Investments in DEP I Midstream Businesses	$ 510.2	$ 512.7	$ 502.7
Investments in DEP II Midstream Businesses	$ 709.7	$ 730.5	$ --
Long-term debt	$ 457.3	$ 484.3	$ 200.0
Partners' equity	$ 761.4	$ 752.8	$ 314.6

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

	Twelve Months		Eleven Months
	Ended December 31,		
	2009	2008	2007
	(dollars in millions)		
Distributions paid to Duncan Energy Partners L.P. with respect to each period from:			
DEP I Midstream Businesses	$ 49.2	$ 93.7	$ 115.3
DEP II Midstream Businesses	$ 86.5	$ 5.6	$ --

Generally, 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 distributed 98% to EPO and 2% to us.

The initial annualized return rate for 2009 was 11.85%, and was determined by EPO and us 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 will be 12.087%. 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. At December 8, 2008 and December 31, 2009, our Distribution Base was $730.0 million. EPO’s Distribution Base was $452.1 million and $817.9 million at December 8, 2008 and December 31, 2009, respectively. The increase in EPO’s Distribution Base is the result of its decision to fund 100% of the expansion capital projects of the DEP II Midstream Businesses since December 8, 2008. We have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, although we may elect to invest in existing or future expansion projects at a later date.

We and EPO received $86.5 million and $29.8 million, respectively, in cash distributions from the DEP II Midstream Businesses for the twelve months ended December 31, 2009. The $86.5 million (or, approximately, $21.6 million each quarter) received by us with respect to 2009 represents the annualized return rate for 2009 of 11.85% 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 2009, it was entitled to $83.4 million of Tier II distributions, of which it received only $29.8 million. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to 2009.

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. 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. 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 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 our significant recent developments since January 1, 2009 through the date of this filing:

Duncan Energy Partners and Enterprise Products Partners Announce Extension of Acadian Gas System into Haynesville Shale Supply Basin

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 rapidly expanding Haynesville Shale natural gas supply basin with access to additional markets through connections with the Acadian Gas System in south Louisiana and nine major interstate natural gas pipelines ("Haynesville Extension"). The Haynesville Shale producing area is believed to cover approximately 2 million acres in northwest Louisiana, almost all of which is under lease. Production from the approximately 200 wells drilled to date is estimated at more than 1 Bcf/d. Over 400 locations are in various stages of drilling and completion with approximately 150 rigs now working in the region.

As currently designed, the Haynesville Extension will have the potential capacity to transport up to 2.1 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with our existing Acadian Gas System. The pipeline is expected to be in service during the third quarter of 2011.

The Acadian Gas System serves major natural gas markets along the Mississippi River corridor between Baton Rouge and New Orleans and has the ability to make physical deliveries into the Henry Hub. The Haynesville Extension will also have interconnects with major interstate pipelines including Florida Gas, Texas Eastern, Transco, Sonat, Columbia Gulf, Trunkline, ANR, Tennessee Gas and Texas Gas. Together with the capacity of the existing Acadian Gas System, the extension project will provide approximately 6.2 Bcf/d of redelivery capacity into an estimated 12 Bcf/d of available downstream pipeline takeaway capacity. Initially, the project will connect to nine Haynesville Shale producer locations in DeSoto and Red River parishes.

Along with providing much needed natural gas takeaway capacity for growing Haynesville production, the new pipeline is expected to provide shippers the opportunity to benefit from additional pricing points and diverse service options and access to the south Louisiana marketplace. For producers, the more flexible contracting options associated with an intrastate pipeline environment is expected to help facilitate a seamless transaction for the producer from the field to the end user.

Currently, we own a 66% equity interest in the entities that own the Acadian Gas System, with EPO owning the remaining 34% equity interest. We are in discussions with EPO regarding the funding and related aspects of the Haynesville Extension project.

Service Begins on Sherman Extension Pipeline

In late February 2009, we and EPO announced that construction had been completed on the 173-mile Sherman Extension expansion of our Texas Intrastate System, which extends through the heart of the prolific Barnett Shale natural gas production basin of north Texas. The completion of the Sherman Extension adds 1.2 Bcf/d of incremental natural gas takeaway capacity from the region, while providing producers in the Barnett Shale, and as far away as the Waha area of west Texas, with greater flexibility to reach the most attractive natural gas markets. The Texas Intrastate System is part of our Natural Gas Pipelines & Services business segment through interconnections with pipelines that serve the Midwest and Northeast regions of the United States.

Initially, the Sherman Extension began providing intrastate service, and its subsequent NGPA 311 transportation was in very limited service due to pipeline integrity issues on the connecting third-party take-away pipeline, the Gulf Crossing Pipeline owned by Boardwalk Pipeline Partners, LP. The Gulf Crossing Pipeline began ramping up its operations on August 1, 2009. As a result, the Sherman Extension started billing its demand charges at 95% of its contracted volumes, which are 950 MMcf/d. Effective September 1, 2009, the Sherman Extension started billing demand charges on 100% of contracted volumes, irrespective of actual transportation volumes. We are currently flowing approximately 700 MMcf/d. The demand charges are approximately $5.0 million a month.

Registration Statements and Equity Offerings

In connection with our June 2009 equity offering, we issued 8,943,400 common units and generated net proceeds of approximately $137.4 million after underwriting discounts and other offering expenses. 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.

In December 2009, we filed a registration statement with the Securities Exchange Commission ("SEC") authorizing the issuance of up to 2,000,000 common units in connection with a distribution reinvestment plan ("DRIP"). 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.

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 and a long-term incentive plan that became effective on February 11, 2010. See Item 9B for additional information regarding the approval of these plans.

General Outlook for 2010

Commercial Outlook

We provide midstream energy services to producers and consumers of natural gas, NGLs 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 contraction that began in late 2007 appeared to show signs of stabilizing in the second half of 2009 with most of the twenty largest developed economies ("G20") reporting quarter- over-quarter growth in real gross domestic product ("GDP") beginning in the third quarter of 2009. However, approximately 65 percent of the G20 were still reporting year-over-year contraction in real GDP in 2009. The United States reported quarter-over-quarter real GDP growth of 2.2 percent and 5.7 percent for the third and fourth quarters of 2009, respectively, after five quarters of contraction in real GDP since the beginning of 2008. Real GDP growth for 2009 compared to 2008 was 0.1 percent.

Impacted by general economic conditions and price shock-induced conservation by consumers, U.S. demand for petroleum products and natural gas (as reported by the U.S. Energy Information Administration) for the first ten months of 2009 decreased approximately 5.4 percent and 2.1 percent, respectively, from the same periods in 2008 and by approximately 11 percent and 1.5 percent, respectively, from the first ten months of 2007. Likewise, U.S. demand for petroleum products for transportation purposes (e.g. motor gasoline, distillate, jet fuel) for the first ten months of 2009 declined by 2.7 percent and 6.3 percent compared to the first ten months of 2008 and 2007, respectively. The rate of decline in U.S. demand for petroleum products since mid-2009 appears to be moderating and demand for natural gas since mid-2009 has increased by 1.5 percent compared to the same period in 2008.

Energy prices have generally rebounded with the recovery in demand, economic growth and stability in the capital markets. The average prices for West Texas Intermediate crude oil and Mont Belvieu ethane for December 2009 increased by approximately 82 percent and 120 percent, respectively, from December 2008; while natural gas at the Henry Hub in December 2009 decreased by 8 percent from December 2008. Notably, there has been a substantial change in the price relationship between natural gas and crude oil. In December 2008, natural gas was priced at 81 percent of crude oil on an energy equivalent basis compared to 41 percent in December 2009. We believe changes in the price relationships of crude oil and crude oil derivatives to natural gas and NGLs in the past year could lead to a long-term structural change in feedstock selection by the petrochemical industry.

During 2009 and the beginning of 2010, natural gas and NGLs have a significant price advantage over more costly crude oil and crude oil derivatives (such as naphtha). This has been primarily driven by (i) a decline in global crude oil production; (ii) more government-held acreage being off limits to non-sovereign energy companies; (iii) geopolitical risk; (iv) growing demand for crude oil by China and other developing countries; (v) the globalization of natural gas prices with more LNG facilities becoming operational; and (vi) the technological breakthroughs around the development of natural gas shale resource basins that have decreased finding and development costs.

For ethylene producers, the largest consumers of NGLs, this has meant that ethane and propane were their most consistently profitable feedstocks in 2009 and are forecasted to be so in 2010. This feedstock cost advantage and a weak U.S. dollar provided U.S. ethylene producers with a competitive advantage globally, especially relative to naphtha crackers in Europe and Asia. Per industry publications, approximately 24% of 2009 aggregate domestic production of high density polyethylene ("HDPE"), low density polyethylene ("LDPE") and PVC were for the export market.

U.S. ethylene producers responded by maximizing the use of NGLs as a feedstock, rationalizing some of their facilities and investing capital to modify their furnaces to crack more NGLs. The U.S. ethylene industry consumed almost 1.3 MMBbls/d of NGL feedstocks in December 2009, an 81 percent increase over 700 MBPD of NGLs consumed in December 2008. We estimate domestic crackers are in the process of adding approximately 100 MBPD of new capacity to crack ethane and propane through modifications to their existing facilities. Certain international ethylene crackers have reacted to the NGL feedstock cost advantage by importing propane to displace crude oil derivatives to feed their heavy crackers, including propane produced in the U.S.

Export ethylene derivative demand remains strong in early 2010, but is expected to moderate as Middle East production increases later this year. Chemical margins in the U.S. are also forecasted to compress due to increased competition, but overall demand for domestically produced ethylene is expected to decline only by approximately 1.5% to 48.3 billion lbs/year in 2010 and then increase 2.3% to 49.4 billion lbs/year in 2011. With the global recession abating, domestic demand is expected to increase, consuming the production that was sold into the export markets in 2008 and 2009.

Strong end user demand for NGLs and increases in NGL-rich natural gas production are expected to (i) keep our NGL fractionators, pipelines and storage facilities operating at high utilization rates and (ii) provide us with opportunities to invest capital to build new natural gas gathering and NGL pipeline facilities.

Natural gas prices have significantly declined from a peak of over $13.00 per MMBtu in mid-2008 to $5.35 per MMBtu in December 2009. This price decrease coupled with the residual impact of a higher cost of capital for certain energy companies has generally resulted in energy companies reducing their drilling capital expenditure budgets. This has led to a substantial decrease in the number of rigs drilling for natural gas in the U.S., declining from a peak of 1,606 rigs in August 2008 to a low of 665 rigs in July 2009 as natural gas prices approached a low of $1.88 per MMBtu in September 2009. The natural gas rig count has since rebounded to 878 rigs at the beginning of February 2010. Even though the total natural gas rig count has dropped by almost half, the substantial efficiencies of horizontal drilling in the non-conventional and shale resource 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. The rig count has increased in the developing Haynesville Shale, Marcellus Shale and Eagle Ford Shale areas where producers are drilling to hold recently executed leases. Generally, rig counts remain significantly below peak levels in areas with conventional natural gas reserves and areas where producers have leases held by production.

In Texas, the rig count at the end of 2009 was 50 percent below peak levels during 2008. Since the end of 2009, the rig count in Texas has increased 13 percent. The rig count in the Barnett Shale area at the end of 2009 was approximately 55 percent below peak levels. While the Barnett Shale has a significant amount of undeveloped natural gas reserves at relatively low finding costs, much of the acreage under lease is held by production. Certain energy companies that were active in the Barnett Shale have elected to reallocate a portion of their capital resources in the near term to drill wells in the Haynesville Shale in northwest Louisiana, the Marcellus Shale in Pennsylvania and West Virginia, and the Eagle Ford Shale in south Texas to secure recently acquired leases that are not held by production. Despite the lower rig count in the Barnett Shale and certain other areas of Texas, we expect transportation volumes on our Texas Intrastate System to increase by up to 10 percent in 2010 with volume growth principally attributable to a full year of operations for the Sherman Extension pipeline and the commencement of operations on the Trinity River Lateral pipeline during the third quarter of 2010. Both of these pipelines serve the Barnett Shale region.

South Texas has seen an increase in drilling activity attributable to the development of the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast and adjacent to our Texas Intrastate System. We have completed several small pipeline projects that enable us to gather and transport up to 300 MMcf/d of new natural gas production from the Eagle Ford Shale. Generally, energy companies have had early success in the Eagle Ford Shale and several have indicated they plan to accelerate their drilling programs. Production associated with this region includes crude oil, NGL-rich natural gas and lean natural gas. We believe there may be opportunities for us to invest capital to incrementally expand our natural gas pipeline and storage facilities and NGL pipeline and fractionation facilities to facilitate production growth from this region.

The rig count in Louisiana has increased 14 percent since the end of 2008 primarily due to development activities in the Haynesville Shale area of northwest Louisiana. Based on industry success, natural gas production from this region is expected to grow rapidly over the next several years. In the fourth quarter of 2009, we announced that seven energy companies had executed long-term agreements to support the Haynesville Extension expansion of our Acadian Gas System. The Haynesville Extension is a 249-mile, 42-inch pipeline designed to transport up to 2.1 Bcf/d. Construction of the pipeline will begin in 2010 and is scheduled to be completed by the end of the third quarter of 2011.

Liquidity Outlook

The debt and equity capital markets have significantly improved since the beginning of 2009. The cost of our term debt and equity capital has generally declined to pre-financial crisis levels. The availability of term debt and equity capital has also improved. The availability of credit commitments from most banks has also improved from a year ago; however, the cost of new bank debt is significantly higher than pre-crisis levels (by approximately 2 percent on borrowed money) and the term of bank capital is generally limited to no more than three years.

Our $300 million Revolving Credit Facility and $282.3 million Term Loan Agreement mature in February and December of 2011, respectively. While we currently believe our credit cost under new bank facilities could increase by approximately 2.0 to 2.5 percent on borrowed money, we believe we will have sufficient liquidity and access to capital markets to refinance these facilities. Based on amounts outstanding under these facilities at December 31, 2009, on an annual basis, we estimate the increase in our credit costs under similar bank facilities currently available in the market could range from approximately $9.0 million to $11.5 million.

In 2007, we executed derivative instruments with an aggregate notional amount of $175 million to reduce our exposure to changes in the 1-month London Interbank Offered Rate ("LIBOR") (which is a part of the cost of our bank credit facility). Under these derivative instruments, our counterparties pay us the 1-month LIBO rate in effect on the periodic reset date and we pay our counterparties an average fixed rate of 4.62 percent. In 2009, our aggregate net payments to counterparties under these derivative instruments and corresponding increase in interest expense was approximately $6.5 million. These derivative instruments expire in September 2010. In the near term, the expiration of these derivative instruments should reduce our future interest expense; however, upon termination, 100 percent of our debt will be subject to changes in the 1-month LIBO rate.

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 2013.

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 large issuance of U.S. Treasury debt and the prevailing economic and capital market conditions will have on the cost and availability of capital.

We expect our proactive approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, and available borrowing capacity under our credit facilities, to provide us with a foundation to meet our anticipated liquidity and capital requirements in 2010. We also believe that we will be able to access the capital markets in 2010 to maintain financial flexibility.

Results of Operations

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.

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 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 management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash consolidated 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 consolidation. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interests.

We include equity earnings from Evangeline in our measurement of segment gross operating margin and operating income. Our equity investment in Evangeline is a vital component of our business strategy and important to the operations of Acadian Gas. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Evangeline's operations complement those of Acadian Gas. As circumstances dictate, we may increase our ownership interest in Evangeline or make other equity method investments.

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,		
	2009	2008	2007
Natural Gas Pipelines & Services, net:			
Natural gas throughput volumes (BBtus/d)			
Texas Intrastate System	3,902	4,021	3,550
Acadian Gas System:			
Transportation volumes	436	378	416
Sales volumes (1)	320	331	308
Total natural gas throughput volumes	4,658	4,730	4,274
NGL Pipelines & Services, net:			
NGL throughput volumes (MBPD)			
South Texas NGL System - Pipelines	109	126	124
NGL fractionation volumes (MBPD)			
South Texas NGL System - Fractionators	77	80	72
Petrochemical Services, net:			
Propylene throughput volumes (MBPD)			
Lou-Tex Propylene Pipeline	21	25	25
Sabine Propylene Pipeline	9	10	12
Total propylene throughput volumes	30	35	37

(1) Includes average net sales volumes for Evangeline of 50 BBtus/d for each of the years ended December 31, 2009, 2008 and 2007, 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,		
	2009	2008	2007
Revenues	$ 979.3	$ 1,598.1	$ 1,220.3
Operating costs and expenses	908.3	1,512.8	1,171.0
General and administrative costs	11.2	18.3	13.1
Equity in income of Evangeline	1.1	0.9	0.2
Operating income	60.9	67.9	36.4
Interest expense	14.0	12.0	9.3
Net income	45.8	55.3	23.6
Net loss (income) attributable to noncontrolling interest:			
DEP I Midstream Businesses – Parent	(15.3)	(11.4)	(20.0)
DEP II Midstream Businesses – Parent	60.6	4.0	--
Net income attributable to Duncan Energy Partners	91.1	47.9	3.6

For information regarding our noncontrolling interest amounts, 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,		
	2009	2008	2007
Natural Gas Pipelines & Services	$ 148.2	$ 159.0	$ 122.5
NGL Pipelines & Services	103.4	82.9	87.9
Petrochemical Services	10.5	11.1	14.3
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7

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 13 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2009	2008	2007
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 460.2	$ 1,100.2	$ 794.1
Natural gas transportation services	263.2	246.7	212.8
Natural gas storage services	15.3	8.4	1.5
Total segment revenues	$ 738.7	$ 1,355.3	$ 1,008.4
NGL Pipelines & Services:			
Sales of NGLs	$ 35.0	$ 47.9	$ 40.3
Sales of other products	11.3	15.0	10.8
NGL and petrochemical storage services	104.9	87.4	68.9
NGL fractionation services	29.5	32.4	30.3
NGL transportation services	43.8	43.6	42.5
Other services	2.5	2.3	1.7
Total segment revenues	$ 227.0	$ 228.6	$ 194.5
Petrochemical Services:			
Propylene transportation services	$ 13.6	$ 14.2	$ 17.4
Total consolidated revenues	$ 979.3	$ 1,598.1	$ 1,220.3

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. The $618.8 million year-to-year decrease in our revenues is primarily due to lower energy commodity sales volumes and prices during 2009 relative to 2008. These factors accounted for a $656.6 million year-to-year decrease in revenues from the sale of natural gas and NGLs. Revenues from natural gas transportation and storage services increased $23.4 million year-to-year primarily due to firm capacity reservation fees earned by our Sherman Extension pipeline during 2009. The Sherman Extension pipeline began earning capacity reservation fees during August 2009.

Revenues from NGL fractionation, transportation, storage and other services increased $15.0 million year-to-year primarily due to increased NGL storage activity and higher storage fees. Revenues from propylene transportation decreased $0.6 million year-to-year due to lower transportation volumes in 2009 relative to 2008.

Operating costs and expenses were $908.3 million for 2009 versus $1.51 billion for 2008. The $604.5 million year-to-year decrease in our operating costs and expenses is primarily due to a decrease in the cost of sales associated with our natural gas and NGL marketing activities. The cost of sales of our natural gas and NGL products decreased $644.2 million year-to-year as a result of lower sales volumes and energy commodity prices. Costs and expenses related to natural gas transportation and storage services increased $24.1 million year-to-year. Operating costs and expenses were lower during 2008 when we recorded favorable adjustments for certain audit claims and changes in anticipated costs to complete an environmental remediation project. In addition, operating expenses increased during 2009 due to higher employee compensation and maintenance expenses and operating expenses for the Sherman Extension pipeline.

Costs and expenses of our NGL fractionation, transportation, storage and other services decreased $7.6 million year-to-year primarily due to lower operational measurement losses at Mont Belvieu Caverns' storage complex and lower fuel and maintenance expenses. Collectively, the remainder of our consolidated operating costs and expenses increased $23.2 million year-to-year as a result of higher depreciation expense due to our recent completion of the Sherman Extension pipeline and $4.2 million of non-cash impairment charges recorded in 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, lower energy commodity prices result in a decrease in our revenues attributable to the sale of natural gas and NGLs; however, these lower commodity prices also decrease the associated cost of sales as purchase prices fall. The market price of natural gas (as measured at Henry Hub in Louisiana) 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. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production.

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 is primarily due to lower costs associated with the DEP II Midstream Businesses. Equity earnings from Evangeline increased $0.2 million year-to-year.

Operating income for 2009 was $60.9 million compared to $67.9 million for 2008. Consolidated revenues and certain operating costs and expenses can fluctuate significantly due to changes in energy commodity prices without necessarily affecting our operating income to the same degree. Consequently, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to 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. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding borrowings we made during 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.

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 total net income to arrive at the amount of net income attributable to Duncan Energy Partners L.P. EPO was attributed $15.3 million of the net income of the DEP I Midstream Businesses during 2009 compared to $11.4 million during 2008. The year-to-year variance in EPO's share of the net income of the DEP I Midstream Businesses is primarily due to improved earnings from these businesses. 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.

EPO was attributed $60.6 million of losses in connection with its ownership interests in the DEP II Midstream Businesses during 2009 compared to $4.0 million of losses for the period from December 8, 2008 to December 31, 2008. In the aggregate, the DEP II Midstream Businesses distributed $116.3 million of cash and posted net losses of $0.5 million during 2009. As a result of its priority return rights in the DEP II Midstream Businesses, Duncan Energy Partners received its full cash distributions of $86.5 million and was attributed income of $60.1 million from these businesses for 2009. EPO is attributed a loss to the extent that aggregate net income for the DEP II Midstream Businesses is less than the income attributed by these businesses to Duncan Energy Partners. EPO received $29.8 million in cash distributions from the DEP II Midstream Businesses in 2009.

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 4,658 BBtus/d for 2009 compared to 4,730 BBtus/d for 2008. Gross operating margin from our natural gas pipelines includes $24.8 million of firm capacity reservation fees earned by our Sherman Extension pipeline during 2009. Contributions to gross operating margin from our Sherman Extension pipeline were more than offset by a year-to-year increase in operating expenses on our

Texas Intrastate System, lower revenues from the sale of pipeline condensate and lower natural gas sales volumes and margins on the Acadian Gas System.

Gross operating margin from our Wilson natural gas storage facility increased $5.4 million year-to-year primarily due to higher firm storage reservation fees earned during 2009 compared to 2008.

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. Gross operating margin from Mont Belvieu Caverns' storage complex increased $22.9 million year-to-year. Mont Belvieu Caverns recorded operational measurement losses of $1.7 million for 2009 compared to operational measurement losses of $6.8 million for 2008. Net of operational measurement losses, gross operating margin from Mont Belvieu Caverns' storage complex increased $17.8 million year-to-year as a result of higher revenues due to increased storage reservation and excess throughput fees and higher storage volumes. Collectively, gross operating margin from the remainder of the businesses classified within this segment decreased $2.4 million year-to-year primarily due to lower NGL sales margins and lower 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 is primarily due to lower transportation volumes on our Lou-Tex Propylene Pipeline.

Comparison of Year Ended December 31, 2008 with Year Ended December 31, 2007

Revenues for 2008 were $1.60 billion compared to $1.22 billion for 2007. The $377.8 million year-to-year increase in our revenues is primarily due to higher energy commodity sales volumes and prices during 2008 relative to 2007. These factors accounted for a $317.9 million year-to-year increase in revenues from the sale of natural gas and NGLs. Revenues from our natural gas transportation and storage businesses increased $40.8 million year-to-year primarily due to higher pipeline transportation fees and volumes during 2008 relative to 2007. Revenues from NGL fractionation, transportation, storage and other services increased $22.3 million year-to-year primarily due to increased NGL storage activity and higher storage fees. Revenues from propylene transportation decreased $3.2 million year-to-year due to lower transportation fees and volumes in 2008 relative to 2007.

Operating costs and expenses were $1.51 billion for 2008 versus $1.17 billion for 2007. The $341.8 million year-to-year increase in our operating costs and expenses is primarily due to an increase in the cost of sales associated with our natural gas and NGL marketing activities. The cost of sales of our natural gas and NGL products increased $308.1 million year-to-year as a result of an increase in volumes and energy commodity prices. Costs and expenses from our natural gas transportation and storage businesses increased $15.9 million year-to-year primarily due to higher repair and maintenance expenses. Costs and expenses from NGL fractionation, transportation, storage and other services increased $26.1 million year-to-year primarily due to higher operating costs and expenses from Mont Belvieu Caverns' storage complex. Collectively, the remainder of our consolidated operating costs and expenses decreased $8.3 million year-to-year primarily due to lower depreciation expense for 2008 compared to 2007.

In the first quarter of 2008, we reviewed the assumptions underlying the estimated remaining economic lives of our assets. As a result of our review, we increased the remaining useful lives of certain assets as of January 1, 2008, most notably the assets that constitute our Texas Intrastate System. These revisions extended the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting volumes for these assets had increased their estimated useful life. There were no changes to the residual values of these assets. These revisions prospectively reduced our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. As a result of this change in estimate, depreciation expense decreased by approximately $20.0 million for the year ended December 31, 2008. The reduction in depreciation expense increased operating income and net income by equal amounts from what they would have been absent the change. Overall, depreciation, amortization and accretion expense included in operating costs and expenses was $167.3 million and

$175.3 million for the years ended December 31, 2008 and 2007, respectively. The reduction in depreciation expense in 2008 resulting from the change in estimate was partially offset by depreciation expense on newly constructed assets that were placed in service during 2008, primarily additions to our Texas Intrastate System and Mont Belvieu storage complex.

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 $9.04 per MMBtu during 2008 versus $6.86 per MMBtu during 2007. The weighted-average indicative market price for NGLs was $1.40 per gallon during 2008 versus $1.19 per gallon during 2007.

General and administrative costs were $18.3 million for 2008 compared to $13.1 million for 2007. The $5.2 million year-to-year increase in general and administrative costs is primarily due to higher employee-related costs and professional services. Equity earnings from Evangeline increased $0.7 million year-to-year.

Operating income for 2008 was $67.9 million compared to $36.4 million for 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $31.5 million year-to-year increase in operating income.

Interest expense increased $2.7 million year-to-year primarily due to borrowings we made in connection with the DEP II drop down transaction in December 2008 and a decrease in the amount of interest capitalized during 2008 relative to 2007. Provision for income taxes decreased $3.1 million year-to-year primarily due to lower accruals for the Texas Margin Tax during 2008 compared to 2007.

As a result of items noted in the previous paragraphs, net income increased $31.7 million year-to-year to $55.3 million for 2008 compared to $23.6 million for 2007.

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 total net income to arrive at the amount of net income attributable to Duncan Energy Partners L.P. EPO was attributed $11.4 million of the net income of the DEP I Midstream Businesses during 2008 compared to $20.0 million during 2008. The year-to-year variance in EPO's share of the net income of the DEP I Midstream Businesses is primarily due to the special allocations of operational measurement gains and losses and depreciation expense to EPO. EPO was attributed $4.0 million of losses in connection with its ownership interests in the DEP II Midstream Businesses for the period from December 8, 2008 to December 31, 2008.

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 $159.0 million for 2008 compared to $122.5 million for 2007, a $36.5 million year-to-year increase. Total natural gas throughput volumes were 4,730 BBtus/d for 2008 compared to 4,274 BBtus/d for 2007. Gross operating margin from our Texas Intrastate System increased $23.6 million year-to-year attributable to: (i) a 471 BBtus/d year-to-year increase in natural gas throughput volumes; (ii) increased transportation and capacity reservation fees; and (iii) higher NGL condensate sales revenues. Gross operating margin from our Acadian Gas System increased $6.4 million year-to-year largely due to improved natural gas sales margins during 2008 relative to 2007. Collectively, results for the Texas Intrastate and Acadian Gas Systems include $1.2 million of property damage repair expenses during 2008 resulting from Hurricanes Gustav and Ike. Equity earnings from our investment in Evangeline increased $0.7 million year-to-year primarily due to higher volumes, lower pipeline integrity expenses and lower interest expense during 2008 relative to 2007.

Gross operating margin from our Wilson natural gas storage facility increased $5.8 million year-to-year. Results from this facility were negatively impacted during 2007 due to expenses related to mechanical issues and ongoing repairs. Storage volumes increased during 2008 as we completed repairs and began returning the storage caverns to commercial service.

NGL Pipelines & Services. Gross operating margin from this business segment was $82.9 million for 2008 compared to $87.9 million for 2007, a $5.0 million year-to-year decrease. Gross operating margin from Mont Belvieu Caverns' storage complex decreased $2.7 million year-to-year.

Mont Belvieu Caverns recorded operational measurement losses of $6.8 million for 2008 compared to operational measurement gains of $4.5 million for 2007. Net of operational measurement gains and losses, gross operating margin from Mont Belvieu Caverns' storage complex increased $8.6 million year-to-year as a result of higher revenues due to increased storage reservation and excess throughput fees and higher storage volumes. Collectively, gross operating margin from the remainder of the businesses classified within this segment decreased $2.3 million year-to-year primarily due to higher expenses for repair and maintenance and pipeline integrity on our South Texas NGL System. Segment operating costs and expenses for 2008 include $0.4 million of property damage repair expenses resulting from Hurricane Ike.

Petrochemical Services. Gross operating margin from this business segment was $11.1 million for 2008 compared to $14.3 million for 2007. Petrochemical transportation volumes decreased to 35 MBPD during 2008 from 37 MBPD during 2007. The $3.2 million year-to-year decrease in segment gross operating margin is primarily due to lower transportation volumes and fees 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, business combinations and distributions to our partners. 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 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 our Parent, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2009, we had approximately $121 million of liquidity, which includes availability under our Revolving Credit Facility. At December 31, 2009, our total debt balance was $457.3 million, which includes $175.0 million outstanding under our Revolving Credit Facility and the $282.3 million we borrowed on December 8, 2008 under our Term Loan Agreement. We were in compliance with the covenants of our loan agreements at December 31, 2009 and 2008.

It is our belief that we will continue to have adequate liquidity and capital resources to fund future recurring operating and investing activities for the next twelve months. For a discussion of our liquidity outlook, see “General Outlook for 2010” within this Item 7.

Registration Statements

We may issue equity or debt securities to assist us in meeting our 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 debt and equity securities for general partnership purposes. After taking into account a June 2009 equity offering made under this registration statement (see table below), we can issue approximately $856.4 million of additional securities under this registration statement in the future.

Underwritten Equity Offering	**Number of Common Units Issued**		**Offering Price** (1)		**Net Proceeds** (2) (in millions)
June 2009 underwritten offering (3)	8,943,400	$	16.00	$	137.4

(1) The public offering price, net of the underwriting discount, was $15.36 per unit.
(2) Net proceeds from these equity offerings were used to repurchase an equal number of our common units beneficially owned by EPO.
(3) Includes our underwriters’ exercise of a portion of their 30-day option to purchase additional common units.

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 the 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 did not issue any common units under the DRIP during the year ended December 31, 2009. In February 2010, we issued 10,385 common units in connection with the DRIP.

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 and a long-term incentive plan. These plans became effective on February 11, 2010. See Item 9B for additional information.

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 within this annual report.

	For the Year Ended December 31,					
		2009		**2008**		**2007**
Net cash flows provided by operating activities	$	156.0	$	220.1	$	217.1
Cash used in investing activities		383.2		748.8		352.4
Cash provided by financing activities		218.1		539.5		137.5

We use the indirect method to compute net cash flows provided by operating activities. 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 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 manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows.

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 2009 with 2008

Operating activities. Net cash flows provided by operating activities were $156.0 million for the year ended December 31, 2009 compared to $220.1 million for the year ended December 31, 2008. The change in operating cash flow is primarily due to the timing of related cash receipts and disbursements offset by a $9.1 million increase in gross operating margin for the year ended December 31, 2009 in comparison to the year ended December 31, 2008.

Investing activities. Cash flows used in investing activities were $383.2 million for the year ended December 31, 2009 compared to $748.8 million for the year ended December 31, 2008. The $365.6 million year-to-year decrease is primarily due to the completion of growth capital projects on the DEP II Midstream Businesses that were under construction in 2008. In February 2009, we completed the construction of the Sherman Extension Pipeline, which is a component of our Texas Intrastate System. The Sherman Extension Pipeline began operations on August 1, 2009.

Financing activities. Cash flows provided by financing activities were $218.1 million for the year ended December 31, 2009 compared to $539.5 million for the year ended December 31, 2008. The $321.4 million year-to-year decrease is due to: (i) a $222.9 million decrease in net contributions, primarily related to growth capital projects, from EPO as both a former owner (pre-drop down) and as noncontrolling interest; (ii) a $311.2 million decrease in net borrowings under our loan agreements; (iii) a $54.5 million increase in distributions to our unitholders and general partners; (iv) a $14.0 million increase in distributions to EPO; and (v) a $280.5 decrease in distributions to EPO related to the DEP II drop down in 2008.

Comparison of 2008 with 2007

Operating activities. Net cash flows provided by operating activities were $220.1 million for the year ended December 31, 2008 compared to $217.1 million for the year ended December 31, 2007. The improvement in operating cash flow is generally due to the increase in gross operating margin between periods (see “Results of Operations” included within this Item 7) adjusted for the timing of related cash receipts and disbursements.

Investing activities. Net cash flows used in investing activities were $748.8 million for the year ended December 31, 2008 compared to $352.4 million for the year ended December 31, 2007. The increase of $396.4 million is primarily due to growth capital spending for additions to property, plant and equipment of the DEP II Midstream Businesses (e.g., the Sherman Extension Pipeline).

Financing activities. Net cash flows provided by financing activities were $539.5 million for the year ended December 31, 2008 compared to $137.5 million for the year ended December 31, 2007. The increase of $402.0 million is primarily due to: (i) a $378.8 million year-to-year increase in contributions by the former owners of the DEP II Midstream Businesses primarily due to the funding of growth capital spending of these businesses; (ii) a $78.3 million year-to-year increase in contributions from EPO primarily due to growth capital spending of the DEP I Midstream Businesses; (iii) a year-to-year increase of $84.2 million in net borrowings under loan agreements, which consisted primarily of $282.3 received from the execution of our Term Loan Agreement; (iv) a $290.0 million year-to-year decrease in net proceeds from equity offerings; and (v) a $179.0 million year-to-year decrease in distributions to EPO related to the DEP I and DEP II drop down transactions.

Capital Expenditures

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

	For the Twelve Months Ended December 31,	
	2009	**2008**
DEP I Midstream Businesses:		
Expansion capital spending (1)	$ 28.5	$ 127.7
Sustaining capital expenditures (2)	13.9	12.8
DEP II Midstream Businesses:		
Expansion capital spending (1)	311.0	576.5
Sustaining capital expenditures (2)	35.7	42.5
Total capital spending	$ 389.1	$ 759.5

(1) EPO funded 100% of expansion capital spending during the periods presented.
(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 2009 and 2008 was attributable to ongoing expansions of the Texas Intrastate System, including the Sherman Extension and Trinity River Lateral projects.

Based on information currently available, we estimate our consolidated capital spending for property, plant and equipment for 2010 will approximate $840 million, which includes estimated expenditures of approximately $780 million for growth capital projects and approximately $60 million for sustaining capital expenditures.

Our forecast of capital expenditures is based on current announced growth plans. With respect to growth capital spending, EPO (as Parent) funds the majority of such project costs under agreements executed in connection with the DEP I and DEP II drop down transactions. In order to fund its share of growth capital spending, Duncan Energy Partners depends on its ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements and the issuance of equity. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding EPO's funding of certain growth capital spending of South Texas NGL and Mont Belvieu Caverns. For information regarding the expansion capital funding arrangements of the DEP II Midstream Businesses, see "Significant Relationships and Agreements with EPO - Company and Limited Partnership Agreements - DEP II Midstream Businesses" under Note 15 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

At December 31, 2009, we had approximately $175.3 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to expansion projects on our Texas Intrastate System and Acadian Gas System.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas 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.

In April 2002, a subsidiary of EPO acquired several midstream energy assets, which included the Texas Intrastate System from El Paso Corporation ("El Paso"). With respect to these assets, El Paso agreed to indemnify our subsidiary for any pipeline integrity costs it incurred (whether paid or payable) for five years following the acquisition date. The indemnity provisions did not take effect until such costs exceeded $3.3 million annually; however, the amount reimbursable by El Paso was capped at $50.2 million in the aggregate. In 2007, the DEP II Midstream Businesses recovered $31.1 million from El Paso related to the 2006 pipeline integrity expenditures. During 2007, the DEP II Midstream Businesses also received the final payment of $5.4 million from El Paso related to this indemnity.

The following table summarizes our pipeline integrity costs, net of indemnity payments received from El Paso, for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2009	**2008**	**2007**
Expensed	$ 14.1	$ 20.6	$ 14.9
Capitalized	17.0	22.9	24.1
Total	$ 31.1	$ 43.5	$ 39.0

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $42.5 million for 2010.

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 assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets into service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include:

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

§ changes in technology that render an asset obsolete;

§ changes in expected salvage values; or

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

At December 31, 2009 and 2008, the net book value of our property, plant and equipment was $4.55 billion and $4.33 billion, respectively. We recorded $176.7 million, $158.5 million and $163.4 million in depreciation expense for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our property, plant and equipment, including changes made in the first quarter of 2008 in the estimated remaining useful lives of certain of our assets, 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

In general, 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. 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 assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

During 2009, we recognized $4.2 million of asset impairment charges, which are reflected as a component of operating costs and expenses. No such asset impairment charges were recorded in 2008 or 2007. We did not recognize any impairment charges related to our equity method investment in Evangeline during the three years ended December 31, 2009.

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 Products Partners 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 production 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, 2009 and 2008, the carrying value of our intangible asset portfolio was $43.8 million and $52.3 million, respectively. We recorded $8.5 million, $9.1 million and $7.2 million in amortization expense associated with our intangible assets for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our intangible assets, see Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 within 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 the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of 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, 2009 and 2008. Our goodwill represents an allocation to the DEP II Midstream Businesses of the goodwill recorded by Enterprise Products Partners 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, 2009.

For additional information regarding our goodwill, see Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 within 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
- § collectability 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 strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2009, 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, 2009 and 2008, we had a liability for environmental remediation of $0.5 million and $0.6 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 within this annual report for additional information regarding environmental matters.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our 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 our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are ongoing and take place over several months. In some cases, settlements of imbalances accumulated over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which we believe is representative of the value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

The following table presents our natural gas imbalance receivables/payables at the dates indicated:

	December 31,	
	2009	2008
Natural gas imbalance receivables	$ 9.8	$ 35.7
Natural gas imbalance payables (1)	11.0	43.6

(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 coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage. 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, 2009 (dollars in millions). For additional information regarding these obligations, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

	Payment or Settlement due by Period				
Contractual Obligations (1)	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of long term debt (2)	$ 457.3	$ --	$ 457.3	$ --	$ --
Estimated cash interest payments (3)	$ 14.8	$ 11.1	$ 3.7	$ --	$ --
Operating lease obligations (4)	$ 115.6	$ 9.0	$ 17.6	$ 14.0	$ 75.0
Purchase obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas (5)	$ 511.7	$ 257.3	$ 254.4	$ --	$ --
Other	$ 0.1	$ *	$ 0.1	$ --	$ --
Underlying major volume commitments:					
Natural gas (in BBtus)	77,207	40,657	36,550	--	--
Capital expenditure commitments (6)	$ 175.3	$ 175.3	$ --	$ --	$ --
Other long-term liabilities (7)	$ 6.4	$ --	$ 0.2	$ --	$ 6.2
Total	$ 1,281.2	$ 452.7	$ 733.3	$ 14.0	$ 81.2

* Indicates amounts are immaterial and less than $0.1 million.

(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 principle amount of consolidated debt obligations outstanding at December 31, 2009. In calculating these amounts, we applied the weighted-average variable interest rates paid during 2009 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 in 2009 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2009. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding these derivative instruments.

(4) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs and (ii) 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 natural gas purchase commitments of Acadian Gas to satisfy its sales commitments to Evangeline. 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, 2009 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 $113.9 million from EPO.

(7) As reflected on our Consolidated Balance Sheet at December 31, 2009, other long-term liabilities primarily represent noncurrent portions of asset retirement obligations. For information regarding our asset retirement obligations, see Note 7 of our Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Off-Balance Sheet Arrangements

At December 31, 2009, Evangeline's debt obligations consisted of (i) $3.2 million in principal amount of 9.90% fixed rate Series B senior secured notes due December 2010 and (ii) a $7.5 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 our non-GAAP measure of total segment gross operating margin to GAAP operating income and net income for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2009	**2008**	**2007**
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(186.3)	(167.3)	(175.3)
Impairment charge included in operating costs and expenses	(4.2)	--	--
Gain on asset sales and related transactions in operating costs and expenses	0.5	0.5	0.1
General and administrative costs	(11.2)	(18.3)	(13.1)
GAAP operating income	60.9	67.9	36.4
Other income (expense), net	(13.8)	(11.5)	(8.6)
Provision for income taxes	(1.3)	(1.1)	(4.2)
GAAP net income	$ 45.8	$ 55.3	$ 23.6

Recent Accounting Developments

The accounting standard setting bodies have recently issued accounting guidance that will or may affect our future financial statements:

§ Fair Value Measurements; and

§ Consolidation of Variable Interest Entities

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

See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our derivative instruments outstanding and related hedging activities, including associated fair value measurements. See Note 12 of the Notes to Consolidated Financial Statements for information regarding the impact of derivative instruments on accumulated other comprehensive loss as reported on our Consolidated Balance Sheets.

Interest Rate Derivative Instruments

We utilize interest rate swaps to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolio (dollars in millions).

		Portfolio FV at		
Scenario	**Resulting Classification**	**December 31, 2008**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying interest rates	*Liability*	$ 9.8	$ 5.5	$ 5.7
FV assuming 10% increase in underlying interest rates	*Liability*	9.4	5.5	5.7
FV assuming 10% decrease in underlying interest rates	*Liability*	10.2	5.6	5.7

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, 2008**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (0.1)	$ *	$ *
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(0.1)	*	*
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(0.1)	*	*

* Indicates that amounts are negligible and less than $0.1 million

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 "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.***

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 chief executive officer (our principal executive officer) (the "CEO") 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) or in other factors during the fourth quarter of 2009, 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, 2009

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, 2009. 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, 2009, 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, 2010.

/s/ Richard H. Bachmann	*/s/ W. Randall Fowler*
Name: Richard H. Bachmann	Name: W. Randall Fowler
Title: Chief Executive Officer of our general partner, DEP Holdings, LLC	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, 2009, 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, 2009. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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, 2009 of the Company and our report dated March 1, 2010 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, 2010

Item 9B. ***Other Information.***

Benefit Plans Approved by Written Consent

On December 10, 2009, the Board unanimously approved a resolution adopting both the 2010 Plan and the EUPP. The 2010 Plan provides for awards of options to purchase common units, restricted common units, common unit appreciation rights ("UARs"), phantom units and distribution equivalent rights ("DERs") to employees, directors or consultants providing services to us and our subsidiaries. The Board authorized the issuance of up to 500,000 common units in connection with this plan. The EUPP provides eligible employees the opportunity to purchase common units at a discount through withholdings from eligible compensation. The Board authorized the issuance of up to 500,000 common units in connection with this plan. On December 30, 2009, the action taken by the Board regarding the plans was approved by written consent of a subsidiary of EPO, which held of record approximately 58.6% of our outstanding common units as of that date. Because EPO's subsidiary held a majority of our common units as of December 30, 2009, no other votes were necessary to adopt the plans. The plans became effective on February 11, 2010.

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, Dan L. Duncan, through his indirect control of EPO and our general partner, has 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. The employees of EPCO who served as directors of DEP GP during 2009 were Messrs. Duncan, Bachmann, Creel, Cunningham, Fowler and Teague.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board 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, Joe D. Havens and Richard S. Snell are "independent" directors under the NYSE rules. In making its determination, the Board's considerations included the fact that Mr. Havens sold (i) 75,865 units of Enterprise GP Holdings L.P. at $19.68 per unit and 100,000 common units of Enterprise Products Partners L.P. at $22.15 per unit to affiliates of Mr. Duncan on February 9, 2009 and (ii) 99,453 units of Duncan Energy Partners L.P. at $15.58 per unit to affiliates of Mr. Duncan on June 23, 2009. The Board's considerations also included the fact that Mr. Duncan has guaranteed outstanding personal bank loans in the aggregate principal amount of $350,000 for which Mr. Casey is the primary obligor. The proceeds of the loans were used by Mr. Casey to purchase a total of 10,900 of our common units in December 2008 and a total of 6,600 common units of Enterprise Products Partners in December 2007, in each case, at prevailing market prices. The units are pledged as collateral to secure the loans.

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, accurate, timely and understandable disclosure in public communications and prompt internal reporting of violations of the code (and thus accountability for adherence to the code).

Governance guidelines, together with 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 four 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, Havens and Snell. 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 20, 2009, Richard H. Bachmann, our 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 20, 2009.

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, 2010.

Name	Age	Position with DEP GP
Dan L. Duncan (1)	77	Director and Chairman
Richard H. Bachmann (1)	57	Director, President and Chief Executive Officer
W. Randall Fowler (1)	53	Director, Executive Vice President and Chief Financial Officer
A. James Teague (1)	64	Director, Executive Vice President and Chief Commercial Officer
Michael A. Creel	56	Director
Dr. Ralph S. Cunningham	69	Director
Larry J. Casey (2)	77	Director
Joe D. Havens (2)	80	Director
William A. Bruckmann, III (2,3)	58	Director
Richard S. Snell (2)	67	Director
William Ordemann (1)	50	Executive Vice President
Bryan F. Bulawa (1)	40	Senior Vice President and Treasurer
Michael J. Knesek (1)	55	Senior Vice President, Principal Accounting Officer and Controller

(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, 2010.

Dan L. Duncan. Mr. Duncan was elected Chairman and a Director of DEP GP in October 2006, Chairman and a Director of EPE Holdings in August 2005, Chairman and a Director of the general partner (now the managing member) of EPO in December 2003 and Chairman and a Director of EPGP in April 1998. Mr. Duncan served as the sole Chairman of EPCO from 1979 to December 2007. Mr. Duncan now serves as Group Co-Chairman of EPCO with his daughter, Ms. Randa Duncan Williams, who is also a director of EPE Holdings. In December 2009, Mr. Duncan was appointed as a Director of LE GP. He also serves as an Honorary Trustee of the Board of Trustees of the Texas Heart Institute at Saint Luke's Episcopal Hospital and on the Board of Trustees of the Baylor College of Medicine.

Richard H. Bachmann. Mr. Bachmann was elected President, Chief Executive Officer and a Director of DEP GP in October 2006 and a Director of EPE Holdings and EPGP in February 2006. Mr. Bachmann previously served as a Director of EPGP from June 2000 to January 2004. Mr. Bachmann has served as Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings since April 2005. Mr. Bachmann was elected Executive Vice President and Chief Legal Officer of EPGP in February 1999 and Secretary of EPGP in November 1999. Mr. Bachmann has served as a director of EPCO since January 1999, as Executive Vice President and Chief Legal Officer of EPCO since May 1999 and as Group Vice Chairman of EPCO since December 2007. In November 2006, Mr. Bachmann was appointed as an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Compensation and Nominating and Governance committees of Constellation Energy Partners LLC and as the chairman of its Conflicts Committee.

W. Randall Fowler. Mr. Fowler was elected Executive Vice President and Chief Financial Officer of DEP GP, EPE Holdings and EPGP in August 2007. Mr. Fowler has served as a Director of DEP GP since September 2006 and EPE Holdings and EPGP since February 2006. Mr. Fowler served as a Senior Vice President and Treasurer of DEP GP from October 2006 to August 2007. Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007. Mr. Fowler also served as Senior Vice President and Chief Financial Officer of EPE Holdings from August 2005 to August 2007. Mr. Fowler was elected President and Chief Executive Officer of EPCO in December 2007. Prior to these elections, he served as Chief Financial Officer of EPCO from April 2005 to December 2007. Mr. Fowler, a certified public accountant (inactive), joined Enterprise Products Partners 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.

A. James Teague. Mr. Teague was elected a Director of DEP GP and Executive Vice President and Chief Commercial Officer in July 2008. He also serves as a Director of EPE Holdings (since October 2009) and a Director of EPGP (since July 2008). Mr. Teague joined the EPCO family of companies in connection with Enterprise Products Partners' acquisition of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Mr. Teague was elected an Executive Vice President of EPGP in November 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.

Michael A. Creel. Mr. Creel was elected a Director of DEP GP in October 2006. From October 2006 to August 2007, Mr. Creel served as the Chief Financial Officer and an Executive Vice President of DEP GP. In August 2007, Mr. Creel resigned these positions with DEP GP and was appointed President and Chief Executive Officer of EPGP.

Mr. Creel, a certified public accountant, has held various senior and executive management positions within the EPCO group of companies since November 1999. Apart from his current position as President and Chief Executive Officer of EPGP and a Director of DEP GP, Mr. Creel also serves as Chief Financial Officer of EPCO (since December 2007) and a Director of EPGP (since February 2006) and as a Director of EPE Holdings (since October 2009). Mr. Creel served as President, Chief Executive Officer and a Director of EPE Holdings from August 2005 through August 2007. From October 2005 through December 2009, Mr. Creel served as a Director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company, which filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code in October 2009 and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a Director of DEP GP in August 2007. In addition to these duties, Dr. Cunningham has served as the President and Chief Executive Officer and a Director of EPE Holdings since August 2007 and a Director of EPGP since February 2006. He served as Group Executive Vice President and Chief Operating Officer of EPGP from December 2005 to August 2007 and Interim President and Interim Chief Executive Officer from June 2007 to August 2007. Dr. Cunningham also served as a Director of EPGP from 1998 to March 2005 and as Chairman and a Director of TEPPCO GP from March 2005 until November 2005.

Dr. Cunningham was elected a Group Vice Chairman of EPCO in December 2007 and served as a Director from 1987 to 1997. He serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), LE GP and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company). In addition, Dr. Cunningham serves as a Director and the Chairman of the Safety, Health and Responsibility Committee of Cenovus Energy Inc. (a Canadian publicly traded oil company). Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995.

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.

Joe D. Havens. Mr. Havens was elected a Director of DEP GP in October 2006. Mr. Havens has been an entrepreneur engaged in the energy, banking and real estate industries. Mr. Havens founded Enterprise Petroleum Company, Inc., the predecessor to EPCO, in 1968, and sold his interest in the successor entity and related businesses to Mr. Duncan in 1990. Mr. Havens also served on the board of Directors of the First Commerce Bank of Corpus Christi, a private bank, from 1991, until he sold his interest in such bank in 2007. Mr. Havens serves on our ACG Committee.

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.

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 Products Partners 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.

William Ordemann. Mr. Ordemann was elected an Executive Vice President of DEP GP in August 2007. He was elected Chief Operating Officer and Executive Vice President of EPGP in August 2007. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and one of its Vice Presidents from October 1999 to September 2001. Prior to joining Enterprise Products Partners, Mr. Ordemann held senior management positions at Shell Midstream Enterprises, LLC and Tejas Natural Gas Liquids, LLC, both of which were affiliates of Shell Oil Company.

Bryan F. Bulawa. Mr. Bulawa was elected Senior Vice President and Treasurer of EPGP, EPE Holdings and DEP GP in October 2009, having served as Vice President and Treasurer of EPGP since July 2007. 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.

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 EPGP since August 2000 and of EPE Holdings since August 2005. He also serves as a Senior Vice President of EPGP (since February 2005) and EPE Holdings (since August 2005). He previously served as Vice President of EPGP from August 2000 to February 2005. Mr. Knesek has been the Controller and a Vice President of EPCO since 1990.

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.

Six of our directors are employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include: for Mr. Duncan, over 55 years of ownership and management of a number of midstream businesses, including as one of the founders of Enterprise Products Partners; for Mr. Bachmann, over 28 years of experience with our midstream assets, including legal, regulatory, contract and merger and acquisitions and, for over the last ten years, as a member of Enterprise Products Partners' executive management team; for Mr. Fowler, 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 Products Partners' executive management team; for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for the Enterprise Products Partners' businesses; for Mr. Creel, over 30 years of management experience with midstream assets, for both third parties and Enterprise Products Partners, including finance and accounting (certified public accountant) and more than six years of management experience in the financial industry; and for Dr. Cunningham, over 45 years of refined products, chemicals, and midstream businesses.

Our four 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. Havens, entrepreneur and one of the co-founders, along with Mr. Duncan, of the predecessor company to Enterprise Products Partners; 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 2009. All such reporting was done in a timely manner in 2009, except that on February 26, 2009, Mr. Havens filed a late Form 4 reporting two purchase transactions that he inadvertently failed to timely report during 2008. In addition, on February 11, 2010, Mr. Havens filed a late Form 4 reporting one purchase transaction (executed on February 8, 2010) that he inadvertently failed to report by the reporting deadline on February 10, 2010.

Item 11. *Executive 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, a privately held company controlled by Dan L. Duncan. 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, 2009, 2008 and 2007 for the chief executive officer, chief financial officer and three other most highly compensated executive officers of our general partner as of December 31, 2009. Collectively, these five individuals were our "named executive officers" for 2009.

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Comp. ($) (4)	Total ($)
Richard H. Bachmann	2009	$ 129,000	$ 190,000	$ 550,867	$ 133,080	$ 47,295	$ 1,050,242
(President and Chief Executive Officer)	2008	159,688	106,250	972,925	35,700	59,055	1,333,618
	2007	71,508	43,338	284,979	18,733	22,077	440,635
W. Randall Fowler	2009	55,781	95,625	262,684	65,416	21,660	501,166
(Executive Vice President and	2008	63,594	43,750	459,152	17,850	20,882	605,228
Chief Financial Officer)	2007	22,675	13,800	112,337	6,295	5,684	160,791
A. J. Teague (5)	2009	162,500	237,500	611,396	166,350	58,437	1,236,183
(Executive Vice President and Chief Commercial Officer)							
William Ordemann (6)	2009	63,232	49,600	262,919	90,552	35,275	501,578
(Executive Vice President)	2008	15,656	10,600	71,192	5,712	6,314	109,474
Michael J. Knesek	2009	50,700	27,625	158,996	54,064	17,099	308,484
(Senior Vice President, Controller	2008	61,800	26,000	185,478	14,280	21,200	308,758
and Principal Accounting Officer)	2007	22,089	9,000	69,381	6,030	5,814	112,314

(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 2009 were paid in February 2010).

(2) Amounts represent the aggregate grant date fair value of restricted unit and Employee Partnership profits interests 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 herein.

(3) Amounts represent 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 herein.

(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. Teague was elected our Chief Commercial Officer in July 2008. Mr. Teague devoted a minimal amount of his time to our business activities during 2008 and instead indirectly supervised the activities of other personnel who were more directly involved in our affairs.

(6) Mr. Ordemann devoted a minimal amount of his time to our business activities during 2007 and instead indirectly supervised the activities of other personnel who were more directly involved in our affairs. As a result, Mr. Ordemann allocated a nominal amount of his compensation to us in 2007.

Each of the named executive officers continues to perform services for Enterprise Products Partners and other affiliates of EPCO. Our named executive officers devote less than a majority of their time to our matters and allocate less than a majority of their compensation to us. 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
Richard H. Bachmann (CEO)	2009	20%	80%	100%
	2008	25%	75%	100%
	2007	12%	88%	100%
W. Randall Fowler (CFO)	2009	11%	89%	100%
	2008	12%	88%	100%
	2007	5%	95%	100%
A. James Teague	2009	25%	75%	100%
William Ordemann	2009	16%	84%	100%
	2008	4%	96%	100%
Michael J. Knesek	2009	16%	84%	100%
	2008	20%	80%	100%
	2007	8%	92%	100%

Our named executive officers did not specifically allocate any of their time to the DEP I or DEP II Midstream Businesses prior to the respective drop down transactions in February 2007 and December 2008, respectively. As a result, we cannot indicate the historical salaries or other elements of compensation that would have been allocated to us pursuant to the ASA had these businesses been owned by us for all periods presented.

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 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. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to the compensation of our named executive officers. The following elements of compensation, and EPCO’s decisions with respect to determination of payments, are not subject to approvals by the Board or the ACG Committee of our general partner. Equity awards under EPCO’s long-term incentive plans are approved by the ACG Committee of the respective issuer. We do not have a separate compensation committee.

As discussed below, the elements of EPCO’s compensation program, along with EPCO’s other rewards (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objectives of EPCO’s compensation program are to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. Our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both the partnership and individual levels. With respect to the three years ended December 31, 2009, 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, 2009, 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. Duncan and EPCO with compensation decisions, Mr. Creel and Dr. Cunningham (both Group Vice Chairmen for EPCO) and the senior vice president of Human Resources for EPCO formulate preliminary compensation recommendations for the named executive officers that are at the executive vice president level and above. Mr. Duncan, after consulting with the senior vice president of Human Resources for EPCO, independently makes compensation decisions with respect to the named executive officers at the executive vice president level and above. With respect to our named executive officer that is a senior vice president, Messrs. Creel and Cunningham, after consultation with the senior vice president of Human Resources for EPCO, make compensation decisions regarding such individual. 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.

Periodically, EPCO will engage a third-party consultant to review compensation elements provided to our executive officers. In 2009, EPCO engaged Hewitt & Associates ("Hewitt") to review executive compensation relative to our industry. Hewitt provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and external trends. Neither we, nor EPCO, which engages the consultant, are aware of the identity of the companies whose data was used from the consultant's proprietary data base for specific positions. EPCO uses the information provided in the Hewitt analysis to gauge whether compensation levels reported by the consultant are within the general ranges of compensation for EPCO employees in similar positions, but that comparison is only a factor taken into consideration and may or may not impact compensation of our executive officers, for which Dan L. Duncan has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our named executive officers in connection with determining compensation for services performed for us; rather, Mr. Duncan 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. Duncan 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. Duncan and EPCO also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan's ultimate decision-making authority, except for equity awards under EPCO's long-term incentive plans, as discussed below.

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

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

The awards granted under EPCO's long-term incentive plans to our named executive officers were determined by consultation among Mr. Duncan, Mr. Creel and the senior vice president of Human Resources for EPCO, and were approved by the ACG Committee of the respective issuer. In addition, our named executive officers are Class B limited partners in certain of the Employee Partnerships. Mr. Duncan approves the issuance of all limited partnership interests in the Employee Partnerships to our named executive officers. See "Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants" below for information regarding EPCO's long-term incentive plans.

EPCO generally does not pay for perquisites for any of our named executive officers, other than reimbursement of certain parking expenses, and expects to continue its policy of covering limited perquisites allocable to our named executive officers. 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, 2009.

In December 2009, EPCO and the partners of each of the Employee Partnerships amended the partnership agreement of each of the Employee Partnerships to provide that the expected liquidation date for such Employee Partnership will be in February 2016. The extensions of the expected liquidation dates were intended to align the interests of the employee partners of the Employee Partnerships with the long-term interests of EPCO and other unitholders in the relevant underlying publicly traded partnerships, which also hold indirectly a significant ownership interest in both us and our subsidiaries.

Also in December 2009, the Board implemented certain equity ownership guidelines for directors and executive officers of our general partner in order to further align their interests and actions with the interests of our partnership and its unitholders. See "Security Ownership of Management" within Item 12 of this annual report for additional information. Our compensation practices for our named executive officers are not expected to be impacted by this new policy.

We believe that each of the base salary, cash bonus awards, and long-term incentive awards 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 2009

The following table presents information concerning each grant of a plan-based award made to a named executive officer in 2009 for which we will be allocated by EPCO our pro rata share under the ASA. The restricted unit and unit option awards granted during 2009 were under EPCO's long-term incentive plans. See "Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants" within this discussion of compensation of directors and executive officers for additional information regarding the long-term incentive plans under which these awards were granted.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted unit awards: (2)						
Richard H. Bachmann (CEO)	5/6/09	--	37,400	--	--	$ 186,402
W. Randall Fowler (CFO)	5/6/09	--	34,000	--	--	90,024
A. James Teague	5/6/09	--	37,400	--	--	233,002
William Ordemann	5/6/09	--	30,000	--	--	119,616
Michael J. Knesek	5/6/09	--	12,500	--	--	50,619
Unit option awards: (3)						
Richard H. Bachmann (CEO)	2/19/09	--	60,000	--	$ 22.06	79,560
	5/6/09	--	60,000	--	24.92	53,250
W. Randall Fowler (CFO)	2/19/09	--	52,500	--	22.06	36,983
	5/6/09	--	60,000	--	24.92	28,433
A. James Teague	2/19/09	--	60,000	--	22.06	99,450
	5/6/09	--	60,000	--	24.92	66,900
William Ordemann	2/19/09	--	45,000	--	22.06	47,736
	5/6/09	--	60,000	--	24.92	42,816
Michael J. Knesek	2/19/09	--	30,000	--	22.06	32,321
	5/6/09	--	30,000	--	24.92	21,743
Profits interest awards: (4)						
Richard H. Bachmann (CEO)	12/2/09	--	--	--	--	364,465
W. Randall Fowler (CFO)	12/2/09	--	--	--	--	172,660
A. James Teague	12/2/09	--	--	--	--	378,394
William Ordemann	12/2/09	--	--	--	--	143,303
Michael J. Knesek	12/2/09	--	--	--	--	108,377

(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 2009. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will equal these amounts over the vesting period.

(2) Awards granted during 2009 were made under the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan").

(3) Awards granted during 2009 were made under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan").

(4) Awards represent each named executive officer's share of the aggregate incremental fair value resulting from the extension of the liquidation date (a material modification of the underlying awards) of each Employee Partnership to February 2016.

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 2009 Award Grants

The following information summarizes the principal types of awards granted to our named executive officers under EPCO's long-term incentive plans. 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 units, phantom units and distribution equivalent rights ("DERs"). Awards granted under the 2008 Plan may be in the form of unit options, restricted units, phantom units and DERs. As of December 31, 2009, no phantom unit awards, UARs or associated DERs have been granted under the EPCO plans to the named executive officers. No awards with respect to our common units have been granted in connection with these long-term incentive plans.

As additional long-term incentive arrangements, EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies "profits interests" in certain limited partnerships (the "Employee Partnerships"), which are privately held affiliates of EPCO. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without any capital contributions.

Restricted unit awards. Restricted unit awards allow recipients to acquire common units of Enterprise Products Partners (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 unit grants will vest at a rate of 25% per year beginning one year after the grant date. The fair value of restricted units 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. Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by the respective issuer.

Unit option awards. Under the EPCO plans, non-qualified incentive options to purchase a fixed number of common units of Enterprise Products Partners 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 options, risk-free interest rates, expected distribution yield on Enterprise Products Partners common units, and expected unit price volatility of Enterprise Products Partners common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

Profits interests awards. Profits interest awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which the named executive officers participate own either units of Enterprise GP Holdings or Enterprise Products Partners or a combination of both.

Each Employee Partnership has a single Class A limited partner, which is a privately held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market. In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the partnership agreement) on its investment ("Capital Base") in the Employee Partnership and residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership assets having a fair market value equal to the Class A limited partner's Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest.

The estimated grant date fair values of the profits interests awards were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. The profits interests awards are subject to forfeiture.

The following table presents each named executive officer's share of the total profits interest in the Employee Partnerships at December 31, 2009:

	Percentage Ownership of Class B Interests			
Named Executive Officer	EPE Unit I	EPE Unit III	Enterprise Unit	EPCO Unit
Richard H. Bachmann (CEO)	9.3%	8.9%	10.3%	20.0%
W. Randall Fowler (CFO)	6.2%	8.9%	8.2%	20.0%
A. James Teague	6.2%	7.4%	10.3%	20.0%
William Ordemann	3.1%	5.2%	8.2%	--
Michael J. Knesek	3.1%	3.7%	5.1%	--

Equity Awards Outstanding at December 31, 2009

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2009. The referenced units in the table below are common units of Enterprise Products Partners. 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 table do not represent the amount of expense we expect to recognize in connection with these awards.

Name	Vesting Date	Option Awards: Number of Units Underlying Options Exercisable (#)	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Unit Awards: Number of Units That Have Not Vested (#)(2)	Market Value of Units That Have Not Vested ($)(3)
Restricted unit awards:							
Richard H. Bachmann (CEO)	Various (1)	--	--	--	--	104,000	$ 3,266,640
W. Randall Fowler (CFO)	Various (1)	--	--	--	--	91,100	2,861,451
A. James Teague	Various (1)	--	--	--	--	104,000	3,266,640
William Ordemann	Various (1)	--	--	--	--	86,100	2,704,401
Michael J. Knesek	Various (1)	--	--	--	--	36,300	1,140,183
Unit option awards:							
Richard H. Bachmann:							
August 4, 2005 option grant	8/04/09	35,000	--	$ 26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
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	5/6/13	--	60,000	24.92	12/31/14	--	--
W. Randall Fowler (CFO):							
August 4, 2005 option grant	8/04/09	25,000	--	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
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	5/6/13	--	60,000	24.92	12/31/14	--	--
A. James Teague:							
August 4, 2005 option grant	8/04/09	35,000	--	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
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	5/6/13	--	60,000	24.92	12/31/14	--	--
William Ordemann:							
May 10, 2004 option grant	5/10/08	25,000	--	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	25,000	--	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	30,000	24.85	5/01/16	--	--
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	5/6/13	--	60,000	24.92	12/31/14	--	--
Michael J. Knesek:							
August 4, 2005 option grant	8/04/09	15,000	--	26.47	8/04/15	--	--

May 1, 2006 option grant	5/01/10	--	30,000	24.85	5/01/16	--	--
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	5/6/13	--	30,000	24.92	12/31/14	--	--

(1) Of the 421,500 restricted unit awards presented in the table, 50,400 vest in 2010, 98,800 vest in 2011, 121,000 vest in 2012 and 151,300 vest in 2013.

(2) Amounts represent the total number of restricted unit awards granted to each named executive officer.

(3) Amounts derived by multiplying the total number of restricted unit awards outstanding for each named executive officer by the closing price of Enterprise Products Partners' common units at December 31, 2009 of $31.41 per unit.

The following table presents information concerning each named executive officer's nonvested profits interest awards at December 31, 2009:

Name	Vesting Date (1)	Option Awards: Number of Units Underlying Options Unexercisable (#)	Option Awards: Option Exercise Price ($/Unit)	Option Awards: Option Expiration Date	Unit Awards: Number of Units That Have Not Vested (#)	Unit Awards: Market Value of Units That Have Not Vested ($)
EPE Unit I:						
Richard H. Bachmann (CEO)	8/23/10	--	--	--	--	$ 1,651,767
W. Randall Fowler (CFO)	8/23/10	--	--	--	--	1,109,396
A. James Teague	8/23/10	--	--	--	--	1,109,396
William Ordemann	8/23/10	--	--	--	--	554,698
Michael J. Knesek	8/23/10	--	--	--	--	554,698
Enterprise Unit:						
Richard H. Bachmann (CEO)	2/20/14	--	--	--	--	654,863
W. Randall Fowler (CFO)	2/20/14	--	--	--	--	523,890
A. James Teague	2/20/14	--	--	--	--	654,863
William Ordemann	2/20/14	--	--	--	--	523,890
Michael J. Knesek	2/20/14	--	--	--	--	327,431
EPCO Unit:						
Richard H. Bachmann (CEO)	11/13/13	--	--	--	--	47,506
W. Randall Fowler (CFO)	11/13/13	--	--	--	--	47,506
A. James Teague	11/13/13	--	--	--	--	47,506

(1) In December 2009, the partnership agreements of each Employee Partnership were amended to provide that the expected liquidation date for each Employee Partnership be extended to February 2016. The extensions of the expected liquidation dates are intended to align the interests of the employee partners of each Employee Partnership with the long-term interests of EPCO and other unitholders by providing an incentive to such employees to devote themselves to maximizing the value of the underlying publicly traded partnerships over an extended period of time.

The profits interest awards of the remaining Employee Partnerships had no market (or assumed liquidation) value at December 31, 2009 due to a decrease in the market value of the limited partner interests owned by each Employee Partnership since formation.

Option Exercises and Units Vested

The following table presents the exercise of unit options by and vesting of restricted units (in each case, including common units of Enterprise Products Partners, not Duncan Energy Partners) to our named executive officers during the year ended December 31, 2009 for which we were historically responsible for a share of the related expense of such awards.

Name	Option Awards: Number of Units Acquired on Exercise (#)	Option Awards: Gross Value Realized on Exercise ($) (1)	Unit Awards: Number of Units Acquired on Vesting (#)	Unit Awards: Gross Value Realized on Vesting ($) (2)
Richard H. Bachmann (CEO)	35,000	$ 330,400	10,000	$ 280,500
W. Randall Fowler (CFO)	10,000	93,200	6,000	168,300
A. James Teague	35,000	326,200	10,000	280,500
William Ordemann	--	--	16,000	451,900
Michael J. Knesek	10,000	93,200	5,000	140,250

(1) Amount determined by multiplying the number of units acquired on exercise of the options by the difference between the closing price of Enterprise Products Partners' common units on the date of exercise less the exercise price.

(2) Amount determined by multiplying the number of restricted unit awards that vested during 2009 by the closing price of Enterprise Products Partners' common units on the date of vesting.

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. Accordingly, to the extent that decisions are made regarding the compensation policies pursuant to which our named executive officers are compensated, they are made by Mr. Duncan and EPCO alone (except for equity awards, as previously noted), and not by our Board.

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, 2009,

Submitted by: Dan L. Duncan
Richard H. Bachmann
W. Randall Fowler
A. James Teague
Michael A. Creel
Dr. Ralph S. Cunningham
William A. Bruckmann, III
Larry J. Casey
Joe D. Havens
Richard S. Snell

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 2009. As previously noted, we do not have a separate compensation committee. Mr. Duncan and EPCO alone make compensation policies (except for equity awards, as previously noted), and not our Board.

Director Compensation

Neither we nor DEP GP provide any additional compensation to employees of EPCO who serve as directors of DEP GP. The following table presents information regarding compensation to the independent directors of our general partner, Messrs. Bruckmann, Havens and Casey, during the year ended December 31, 2009. Mr. Snell was elected as a director of our general partner effective January 1, 2010 and therefore did not receive any compensation for service on the Board in 2009.

Name	Fees Earned or Paid in Cash ($)
William A. Bruckmann, III	$ 90,000
Joe D. Havens	$ 75,000
Larry J. Casey	$ 75,000

For 2009, the independent directors were compensated for their services as follows: (i) each received a $75,000 cash retainer annually and (ii) if the individual served as chairman of a committee of the Board, then he received an additional $15,000 in cash annually. Effective January 1, 2010, the annual compensation arrangements for our independent directors changed to the following:

§ Each independent director will receive $75,000 in cash annually;

§ If the individual serves as chairman of a committee of the Board of Directors, then he will receive an additional $15,000 in cash annually;

§ Each independent director will receive a meeting fee of $1,500 in cash for each meeting of the Board attended. In addition, each independent director will receive a meeting fee of $1,500 in cash for each meeting of a duly appointed committee of the Board attended, provided that he is duly elected or appointed to the committee; and

§ Each independent director shall receive 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.

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, 2010, 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	Dan L. Duncan	34,368,640 (1)	59.6%
	1100 Louisiana Street, 10th Floor		
	Houston, Texas 77002		

(1) For a detailed listing of ownership amounts that comprise Mr. Duncan's 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 Products Partners as of February 1, 2010 by (i) our named executive officers; (ii) the current directors of DEP GP; and (iii) the current directors and executive officers of DEP GP as a group. As of February 1, 2010, Enterprise Products Partners owns 100% of the member interests of EPO, which directly owns 100% of the member interests of DEP GP and indirectly owns 58.6% 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 Products Partners that are exercisable within 60 days of the filing date of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the common units of Enterprise Products Partners that are beneficially owned by EPCO and its affiliates. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of Mr. Duncan's family. The address of EPCO is 1100 Louisiana Street, 10th Floor, Houston, Texas 77002.

Name of Beneficial Owner	Duncan Energy Partners L.P. Common Units		Enterprise Products Partners L.P. Common Units	
	Amount and Nature Of Beneficial Ownership	Percent of Class	Amount and Nature Of Beneficial Ownership	Percent of Class
Dan L. Duncan:				
Units owned by EPCO:				
Through DFI Delaware Holdings, L.P.	--	--	130,506,142	21.5%
Through Duncan Family Interests, Inc.	--	--	6,775,839	1.1%
Through DFI GP Holdings L.P.	--	--	3,100,000	*
Through Enterprise GP Holdings L.P.	--	--	21,167,783	3.5%
Through EPCO Holdings, Inc.	99,453	*	6,182,354	1.0%
Units owned by EPO	33,783,587	58.6%	--	--
Units owned by DD Securities LLC	103,100	*	1,392,686	*
Units owned by Employee Partnerships (1)	--	--	1,623,654	*
Units owned by family trusts (2)	--	--	14,624,718	2.4%
Units owned personally	382,500	*	1,470,006	*
Total for Dan L. Duncan	34,368,640	59.6%	186,843,182	30.8%
Richard H. Bachmann (CEO) (3,4)	14,172	*	233,238	*
W. Randall Fowler (CFO) (3,5)	2,000	*	153,674	*
A. James Teague (3,6)	6,000	*	295,228	*
Michael A. Creel (7)	7,500	*	248,868	*
Dr. Ralph S. Cunningham	3,000	*	104,739	*
Larry J. Casey	10,900	*	6,600	*
Joe D. Havens	11,664	*	232,723	*
William A. Bruckmann, III	4,500	*	4,800	*
Richard S. Snell	1,000	*	2,064	*
William Ordemann (3)	3,810	*	117,119	*
Michael J. Knesek (3,8)	1,340	*	67,853	*
All current directors and executive officers of DEP GP, as a group (13 individuals in total) (9)	34,436,726	59.7%	188,330,298	31.1%

* Represents a beneficial ownership of less than 1% of class

(1) As a result of EPCO's ownership of the general partners of the Employee Partnerships, Mr. Duncan is deemed beneficial owner of the limited partner interests held by these entities.

(2) Mr. Duncan is deemed beneficial owner of the limited partner interests held by certain family trusts, the beneficiaries of which are shareholders of EPCO.

(3) These individuals are named executive officers.

(4) The number of Enterprise Products Partners' common units presented for Mr. Bachmann includes 35,000 common unit options that are exercisable within 60 days of the filing date of this report.

(5) The number of Enterprise Products Partners' common units presented for Mr. Fowler includes 25,000 common unit options that are exercisable within 60 days of the filing date of this report.

(6) The number of Enterprise Products Partners' common units presented for Mr. Teague includes 35,000 common unit options that are exercisable within 60 days of the filing date of this report.

(7) The number of Enterprise Products Partners' common units presented for Mr. Creel includes 35,000 common unit options that are exercisable within 60 days of the filing date of this report.

(8) The number of Enterprise Products Partners' common units presented for Mr. Knesek includes 709 common units held by a family member for which he has disclaimed beneficial ownership and 15,000 common unit options that are exercisable within 60 days of the filing date of this report.

(9) Cumulatively, this group's beneficial ownership amount includes 145,000 options to acquire Enterprise Products Partners common units that were issued under the 1998 Plan. These options vested in prior periods and remain exercisable within 60 days of the filing date of this annual report.

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 units representing limited partnership interests in Enterprise Products Partners or Enterprise GP Holdings L.P. (each of which we refer to as an "Affiliated MLP"), owned by an executive officer of our general partner who is also an executive officer of the general partner of such Affiliated MLP, shall be counted toward the equity ownership requirements set forth above.

Securities Authorized for Issuance Under Equity Compensation Plans

Duncan Energy Partners did not have any securities authorized for issuance under any effective equity compensation plans as of December 31, 2009. For information regarding the newly adopted 2010 Plan and EUPP, each of which became effective on February 11, 2010, see Item 9B of this annual report.

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

Certain Relationships and Related Party 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 into this Item 13.

Review and Approval of Transactions with Related Parties

We generally 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 companies owned or controlled by Mr. Duncan such as EPCO), 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 the general partner or the 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 ASA with EPCO govern specified related party transactions, as further described below.

The ACG Committee Charter provides that the ACG Committee is established to review and approve 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 "Item 10. Directors, Executive Officers and Corporate Governance —Partnership Management", " – Corporate Governance" and " – ACG Committee" of this annual report, at December 31, 2009, the ACG Committee was comprised of three directors: William A Bruckmann, Joe D. Havens and Larry J. Casey. Mr. Richard S. Snell was elected as a director in January 2010 and also serves on the ACG Committee. During the year ended December 31, 2009, the ACG Committee reviewed and approved our June 2009 repurchase from EPO of a total of 8,943,400 of our common units in connection with the transactions described in Item 5 of this annual report under the heading "Issuer Purchases of Equity Securities."

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 and our subsidiaries, our general partner and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs, without markup or discount, for those services.

The ACG Committee reviewed and recommended the ASA, and the Board approved it upon receiving such recommendation. For a summary of the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Related party transactions that do not occur under the ASA and that are not reviewed by the ACG Committee, as described above, are subject to the management authorization policy. This policy, which applies to related party transactions as well as transactions with unrelated parties, specifies thresholds for our general partner's officers and chairman of the Board to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements.

Business Opportunity Agreements

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts, 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 Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings 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 and limited partner interests (or securities which have characteristics similar to incentive distribution rights 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 GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP 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 chief executive officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100 million, the chief executive officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, and EPGP and DEP GP, then Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP’s Chief Executive Officer and ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

- § If any business opportunity not covered by the preceding bullet point (i.e., not involving “equity securities”) is presented to the EPCO Group, or to Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100 million, any decision to decline the business opportunity will be made by the chief executive officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100 million, the chief executive officer of EPGP may make the determination to decline the business opportunity without consulting EPGP’s ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity. Should this occur, the EPCO Group may pursue the business opportunity 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 is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our general partner's ACG Committee (i.e., a "Special Approval") or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its resolution of any conflict of interest to consider:

§ the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

§ the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);

§ any customary or accepted industry practices and any customary or historical dealings with a particular person;

§ any applicable generally accepted accounting or engineering practices or principles;

§ the relative cost of capital of the parties and the consequent rates of return to the equity holders of the parties; and

§ such additional factors as the ACG Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable to us, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee's Special Approval is conclusively deemed fair and reasonable to us under our partnership agreement.

The review and work performed by the ACG Committee with respect to a transaction varies depending upon the nature of the transaction and the scope of the ACG Committee's charge. Examples of functions the ACG Committee may, as it deems appropriate, perform in the course of reviewing a transaction include (but are not limited to):

§ assessing the business rationale for the transaction;

- § reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;
- § assessing the effect of the transaction on our earnings and distributable cash flow per unit, and on our results of operations, financial condition, properties or prospects;
- § conducting due diligence, including by interviews and discussions with management and other representatives and by reviewing transaction materials and findings of management and other representatives;
- § considering the relative advantages and disadvantages of the transactions to the parties;
- § engaging third-party financial advisors to provide financial advice and assistance, including by providing fairness opinions if requested;
- § engaging legal advisors; and
- § evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in the partnership agreement requires the ACG Committee to consider the interests of any person other than the partnership. In the absence of bad faith by the ACG Committee or our general partner, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the ACG Committee or our general partner with respect to such matter are conclusive and binding on all persons (including all of our partners) and do not constitute a breach of the partnership agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in the partnership agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. The partnership agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the ACG Committee or our general partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Director Independence

Messrs. Bruckmann, Casey, Havens 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 – 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,	
	2009	**2008**
Audit Fees (1)	$ 0.9	$ 1.0
Audit-Related Fees (2)	--	--
Tax Fees (3)	--	0.2
All Other Fees (4)	N/A	N/A

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements, or (iii) those services normally provided in connection with 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. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(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. This category primarily includes services relating to the preparation of unitholder annual K-1 statements and partnership tax planning. In 2008, PricewaterhouseCoopers International Limited was engaged to perform the majority of tax related services.

(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 years ended December 31, 2009 and 2008.

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. 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 10.8 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.4***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.5***	Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.10 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.6***	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).
10.7***	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).
10.8***	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 8, 2007).
10.9***	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).
10.10***	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 10.2 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.11***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.12***	Form of 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 8, 2007).
10.13***	Amendment to Form of 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 10.4 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.14***	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 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.15***	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).
10.16***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.17***	Form of Unit Appreciation Right Grant Award (DEP Holding, LLC Directors) under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.24 to Form 10-K filed April 2, 2007).
10.18***	Form of Employee Restricted Unit Grant Award under the Enterprise Products Company 2005

	EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.19***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.20***	Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit10.5 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.21***	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).
10.22***	Form of Option Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 26, 2010).
10.23***	Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed February 26, 2010).
10.24***	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).
10.25***	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).
10.26***	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).
10.27***	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 Enteprise Products Partners L.P. on November 18, 2008).
10.28***	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).
10.29***	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).
10.30***	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).
10.31***	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).
10.32***	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).
10.33***	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 Product Partners L.P. on February 28, 2007).
10.34***	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).
10.35***	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).
10.36***	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).
10.37***	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).
10.38***	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).
10.39***	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).
10.40***	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).
10.41	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).
10.42	Purchase and Sale Agreement dated as of December 8, 2008 by and among (a) Enterprise Products Operating LLC and Enterprise GTM Holdings L.P. as Seller Parties and (b) Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P. and DEP OLP GP, LLC as Buyer Parties (incorporated by reference to Exhibit 10.1 of Form 8-K filed December 8, 2008).
10.43	Contribution, Conveyance and Assumption Agreement dated as of December 8, 2008 by and among Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise GTM Holdings L.P. and Enterprise Holding III, L.L.C. (incorporated by reference to Exhibit 10.2 of Form 8-K filed December 8, 2008).
10.44	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).
10.45	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).
10.46	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).
10.47	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).
10.48	Unit Purchase Agreement, dated as of December 8, 2008, by and between Duncan Energy Partners L.P. and Enterprise Products Operating LLC (incorporated by reference to Exhibit 10.9 of Form 8-K filed December 8, 2008).
10.49	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).
10.50	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).
10.51	Revolving Credit Agreement, dated as of January 5, 2007, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.20 to Amendment No. 2 to Form S-1

	Registration Statement (Reg. No. 333-138371) filed January 12, 2007).
10.52	First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto. Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.2 to Form 10-Q filed August 8, 2007).
10.53	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).
10.54	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).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2009, 2008, 2007, 2006 and 2005.
21.1#	List of Subsidiaries as of February 1, 2010.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Richard H. Bachmann for Duncan Energy Partners L.P. for the December 31, 2009 Annual Report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Duncan Energy Partners L.P. for the December 31, 2009 Annual Report on Form 10-K.
32.1#	Section 1350 certification of Richard H. Bachmann for the December 31, 2009 Annual Report on Form 10-K.
32.2#	Section 1350 certification of W. Randall Fowler for the December 31, 2009 Annual Report on Form 10-K.

* With respect to exhibits incorporated by reference to Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P. and Enterprise GP Holdings L.P. are 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 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, 2010.

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 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, 2010.

Signature	Title (Position with DEP Holdings, LLC)
$/s/$ Dan L. Duncan Dan L. Duncan	Director and Chairman
/s/ Richard H. Bachmann Richard H. Bachmann	Director, President and Chief Executive Officer
/s/ W. Randall Fowler W. Randall Fowler	Director, Executive Vice President and Chief Financial Officer
/s/ A. James Teague A. James Teague	Director, Executive Vice President and Chief Commercial Officer
/s/ Michael A. Creel Michael A. Creel	Director
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director
/s/ Larry J. Casey Larry J. Casey	Director
/s/ Joe D. Havens Joe D. Havens	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, 2009 and 2008, 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, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, 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, 2010 expresses 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, 2010

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

	December 31, 2009	December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 3.9	$ 13.0
Accounts receivable – trade, net of allowance for doubtful accounts	77.7	117.3
Accounts receivable – related parties	54.5	3.3
Gas imbalance receivables	9.8	35.7
Inventories	10.5	28.0
Prepaid and other current assets	9.8	4.3
Total current assets	166.2	201.6
Property, plant and equipment, net	4,549.6	4,330.2
Investments in Evangeline	5.6	4.5
Intangible assets, net of accumulated amortization of $42.6 at December 31, 2009 and $34.1 at December 31, 2008	43.8	52.3
Goodwill	4.9	4.9
Other assets	0.7	1.2
Total assets	$ 4,770.8	$ 4,594.7
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable – trade	$ 54.5	$ 45.2
Accounts payable – related parties	13.6	48.5
Accrued product payables	59.9	109.7
Accrued property taxes	9.1	8.3
Accrued taxes – other	8.4	8.3
Other current liabilities	18.9	33.3
Total current liabilities	164.4	253.3
Long-term debt (see Note 11)	457.3	484.3
Deferred tax liabilities	5.8	5.7
Other long-term liabilities	6.4	7.2
Commitments and contingencies		
Equity:		
Duncan Energy Partners L.P. partners' equity: (see Note 12)		
Limited partners		
Common units (57,676,987 common units outstanding at December 31, 2009 and 20,343,100 common units outstanding at December 31, 2008)	766.6	308.2
Class B units (37,333,887 Class B units outstanding at December 31, 2008)	--	453.8
General partner	0.2	0.4
Accumulated other comprehensive loss	(5.4)	(9.6)
Total Duncan Energy Partners L.P. partners' equity	761.4	752.8
Noncontrolling interest in subsidiaries: (see Note 13)		
DEP I Midstream Businesses – Parent	487.3	478.4
DEP II Midstream Businesses – Parent	2,888.2	2,613.0
Total noncontrolling interest	3,375.5	3,091.4
Total equity	4,136.9	3,844.2
Total liabilities and equity	$ 4,770.8	$ 4,594.7

The accompanying notes are an integral part of these financial statements.

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

	For Year Ended December 31,		
	2009	2008	2007
Revenues			
Third parties	$ 492.0	$ 856.4	$ 759.3
Related parties	487.3	741.7	461.0
Total revenues (see Note 14)	979.3	1,598.1	1,220.3
Costs and Expenses			
Operating costs and expenses:			
Third parties	749.0	1,167.7	1,066.7
Related parties	159.3	345.1	104.3
Total operating costs and expenses	908.3	1,512.8	1,171.0
General and administrative costs:			
Third parties	0.3	3.4	1.7
Related parties	10.9	14.9	11.4
Total general and administrative costs	11.2	18.3	13.1
Total costs and expenses	919.5	1,531.1	1,184.1
Equity in income of Evangeline	1.1	0.9	0.2
Operating income	60.9	67.9	36.4
Other income (expense)			
Interest expense	(14.0)	(12.0)	(9.3)
Other, net	0.2	0.5	0.7
Other expense, net	(13.8)	(11.5)	(8.6)
Income before provision for income taxes	47.1	56.4	27.8
Provision for income taxes	(1.3)	(1.1)	(4.2)
Net income	45.8	55.3	23.6
Net loss (income) attributable to noncontrolling interest: (see Note 13)			
DEP I Midstream Businesses - Parent	(15.3)	(11.4)	(20.0)
DEP II Midstream Businesses - Parent	60.6	4.0	--
Total net loss (income) attributable to noncontrolling interest	45.3	(7.4)	(20.0)
Net income attributable to Duncan Energy Partners L.P. (see Note 1)	$ 91.1	$ 47.9	$ 3.6
Allocation of net income attributable to Duncan Energy Partners L.P.: (see Note 1)			
Duncan Energy Partners L.P.:			
Limited partners' interest in net income	$ 90.5	$ 27.8	$ 18.8
General partner interest in net income	$ 0.6	$ 0.5	$ 0.4
Former owners of DEP I Midstream Businesses		n/a	$ 5.0
Former owners of DEP II Midstream Businesses		$ 19.6	$ (20.6)
Basic and diluted earnings per unit (see Note 16)	$ 1.57	$ 1.22	$ 0.93

The accompanying notes are an integral part of these financial statements.

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

	For Year Ended December 31, 2009	2008	2007
Net income	$ 45.8	$ 55.3	$ 23.6
Other comprehensive income (loss):			
Cash flow hedges:			
Interest rate derivative instrument losses during period	(2.5)	(8.0)	(3.3)
Reclassification adjustment for (gains) losses included in net income related to interest rate derivative instruments	6.6	2.0	(0.3)
Commodity derivative instrument losses during period	--	(0.7)	(0.1)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	--	0.7	0.1
Total other comprehensive income (loss)	4.1	(6.0)	(3.6)
Comprehensive income	49.9	49.3	20.0
Comprehensive loss (income) attributable to noncontrolling interest:			
DEP I Midstream Businesses – Parent	(15.3)	(11.4)	(20.0)
DEP II Midstream Businesses – Parent	60.6	4.0	--
Total comprehensive loss (income) attributable to noncontrolling interest	45.3	(7.4)	(20.0)
Comprehensive loss (income) allocated to former owners of DEP II Midstream Businesses	--	(19.6)	20.6
Comprehensive income attributable to Duncan Energy Partners L.P.	$ 95.2	$ 22.3	$ 20.6

The accompanying notes are an integral part of these financial statements.

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

	For Year Ended December 31,		
	2009	2008	2007
Operating activities:			
Net income	$ 45.8	$ 55.3	$ 23.6
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	188.3	167.8	175.6
Equity in income of Evangeline	(1.1)	(0.9)	(0.2)
Gain on sale of assets and related transactions	(0.5)	(0.5)	(0.1)
Deferred income tax expense	--	0.3	3.8
Non-cash asset impairment	4.2	--	--
Changes in fair market value of derivative instruments	(0.2)	(0.1)	0.2
Net effect of changes in operating accounts (see Note 19)	(80.5)	(1.8)	14.2
Cash flows provided by operating activities	156.0	220.1	217.1
Investing activities:			
Capital expenditures	(389.1)	(759.5)	(340.1)
Contributions in aid of construction costs	5.7	9.9	10.0
Proceeds from sale of assets and related transactions	0.9	0.9	12.6
Cash used for business combinations	(0.7)	--	(35.0)
Other	--	(0.1)	0.1
Cash used in investing activities	(383.2)	(748.8)	(352.4)
Financing activities:			
Repayments of debt	(103.2)	(114.7)	(114.0)
Borrowings under debt agreements	76.2	398.9	314.0
Debt issuance costs	(0.4)	(1.6)	(0.5)
Net proceeds from Duncan Energy Partners’ common unit offerings	137.4	0.5	290.5
Common units repurchased from EPO and subsequently retired	(137.4)	--	--
Cash distributions to Duncan Energy Partners’ unitholders and general partner	(88.9)	(34.4)	(21.8)
Cash distributions to noncontrolling interest	(51.6)	(318.1)	(491.0)
Cash contributions from noncontrolling interest	386.0	183.3	105.0
Net cash contributions from former owners of the DEP I Midstream Businesses	--	--	8.5
Net cash contributions from former owners of the DEP II Midstream Businesses	--	425.6	46.8
Cash provided by financing activities	218.1	539.5	137.5
Net changes in cash and cash equivalents	(9.1)	10.8	2.2
Cash and cash equivalents, beginning of period	13.0	2.2	--
Cash and cash equivalents, end of period	$ 3.9	$ 13.0	$ 2.2

The accompanying notes are an integral part of these financial statements.

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

	Former Owners		Duncan Energy Partners				
	DEP I Midstream Businesses	DEP II Midstream Businesses	Limited Partners	General Partner	AOCI	Noncontrolling Interest in Subsidiaries	Total
Balance, January 1, 2007	$ 725.8	$ 2,853.8	$ --	$ --	$ --	$ --	$ 3,579.6
Transactions prior to the DEP I dropdown effective February 1, 2007:							
Net income (loss)	5.0	(0.3)	--	--	--	--	4.7
Net cash contributions (distributions) to former owners	8.5	(8.8)	--	--	--	--	(0.3)
Balance, January 31, 2007	739.3	2,844.7	--	--	--	--	3,584.0
Transactions in connection with Duncan Energy Partners' initial public offering and the DEP I drop down effective February 1, 2007:							
Adjustment for liabilities of DEP I Midstream Businesses not transferred							
Adjustment for liabilities of DEP I Midstream Businesses not transferred to Duncan Energy Partners	2.7	--	--	--	--	--	2.7
Retention by noncontrolling interest of ownership interests	(252.3)	--	--	--	--	252.3	--
Allocation of equity in the DEP I Midstream Businesses to Duncan Energy Partners	(489.7)	--	479.9	9.8	--	--	--
Net proceeds from Duncan Energy Partners' initial public offering	--	--	290.5	--	--	--	290.5
Cash distribution to noncontrolling interest at time of initial public offering	--	--	(450.3)	(9.2)	--	--	(459.5)
Balance, February 1, 2007	$ --	2,844.7	320.1	0.6	--	252.3	3,417.7
Net income (loss)		(20.3)	18.8	0.4	--	20.0	18.9
Amortization of equity awards		--	0.2	--	--	--	0.2
Cash contributions from former owners		55.6	--	--	--	--	55.6
Cash distributions to partners		--	(21.4)	(0.4)	--	--	(21.8)
Cash contributions from noncontrolling interest		--	--	--	--	105.0	105.0
Cash distributions to noncontrolling interest		--	--	--	--	(31.5)	(31.5)
Cash flow hedges		--	--	--	(3.6)	--	(3.6)
Other		0.1	--	--	--	9.4	9.5
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 awards		--	0.2	--	--	--	0.2
Cash contributions from former owner		425.6	--	--	--	--	425.6
Cash contributions from noncontrolling interest		--	--	--	--	161.6	161.6
Cash distributions to noncontrolling interest		--	--	--	--	(37.3)	(37.3)
Cash distributions to partners		--	(33.7)	(0.7)	--	--	(34.4)
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 noncontrolling interest at DEP II drop down		--	(280.5)	--	--	--	(280.5)
Net 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 noncontrolling interest			--	--	--	21.7	21.7
Cash distributions to noncontrolling interest			--	--	--	(0.3)	(0.3)
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 awards	2.2	--	--	--	2.2
Net proceeds from Duncan Energy Partners' common unit offerings	137.4	--	--	--	137.4
Cash contributions from noncontrolling interest	--	--	--	386.0	386.0
Cash distributions to noncontrolling interest	--	--	--	(51.6)	(51.6)
Cash distributions to unitholders and general partner	(88.1)	(0.8)	--	--	(88.9)
Common units repurchased from EPO and retired (see Note 12)	(137.4)	--	--	--	(137.4)
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

The accompanying notes are an integral part of these 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. References to “DEP OLP” mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners through which Duncan Energy Partners conducts substantially all of its business.

References to “Enterprise Products Partners” mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise Products Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “EPD.” References to “EPGP” mean Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners. References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business, and its consolidated subsidiaries. EPO beneficially owns 100% of DEP GP and is a significant owner of our common units. Enterprise Products Partners consolidates our financial statements with those of its own.

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 Products Partners (the “TEPPCO Merger”). On October 26, 2009, Enterprise Products Partners completed the mergers with TEPPCO and TEPPCO GP. On October 27, 2009, Enterprise Products Partners’ TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

References to “Enterprise GP Holdings” mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol “EPE.” Enterprise GP Holdings owns EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC (“EPE Holdings”), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan.

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”). 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.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”).

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”). Our ownership interests in the DEP II Midstream Businesses are held by Enterprise Holding III, L.L.C., which is a wholly owned subsidiary of DEP OLP. Ownership interests in the DEP II Midstream Businesses that were retained by EPO are held by its wholly owned subsidiary, Enterprise GTM Holdings L.P.

Within the context of our financial information, references to “former owners” mean EPO’s ownership interests in the DEP I and DEP II Midstream Businesses prior to the effective date of the related drop down transactions.

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 “EPCO” mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. We, Enterprise Products Partners, EPO, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to “Employee Partnerships” mean EPE Unit L.P. (“EPE Unit I”), EPE Unit II, L.P. (“EPE Unit II”), EPE Unit III, L.P. (“EPE Unit III”), Enterprise Unit L.P. (“Enterprise Unit”) and EPCO Unit L.P. (“EPCO Unit”), collectively, all of which are privately held affiliates of EPCO.

Note 1. Partnership Organization, Primary Operations and Basis of Financial Statement Presentation

Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “DEP.” Duncan Energy Partners is engaged in the business of: (i) natural gas liquids (“NGLs”) transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas.

At December 31, 2009, Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. At December 31, 2009, EPO owned approximately 58.6% of Duncan Energy Partners’ limited partner interests and 100% of DEP GP. DEP GP is responsible for managing the business and operations of Duncan Energy Partners.

A privately held affiliate, EPCO, provides all of our employees and certain administrative services to the partnership.

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.

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 $300.0 million unsecured revolving credit facility (the “Revolving Credit Facility”) and $260.6 million of the $290.5 million of net proceeds from our initial public offering. 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 two 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 1.0 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 263-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% general partner interest in Enterprise GC, (ii) a 51% general partner interest in Enterprise Intrastate and (iii) a 51% 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 $300.0 million senior unsecured term loan agreement (the “Term Loan Agreement”) and $0.5 million of net cash proceeds from an equity offering to EPO. The market value 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, located in south Texas; (ii) a 1,020-mile NGL pipeline system located in south Texas; and (iii) 1,112 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 190-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 6,560-mile Enterprise Texas natural gas pipeline system, which includes the Sherman Extension, and leases the Wilson natural gas storage facility. The Enterprise Texas system, along with the Waha, TPC Offshore and Channel pipeline systems, comprise our Texas Intrastate System.

See “Noncontrolling Interest – 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.

Generally, 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 (based on an initial defined investment of $730.0 million) and then to EPO in amounts sufficient to generate an aggregate initial annualized return on their respective investments of 11.85%. Effective January 1, 2010, the annualized return increased by 2.0% to 12.087%. Distributions in excess of these amounts will be distributed 98% to

EPO and 2% to us. Income and loss of the DEP II Midstream Businesses are first allocated to EPO and us based on each entity's percentage interest of 77.4% and 22.6%, respectively, and then in a manner that in part follows the cash distributions.

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

Basis of Financial Statement Presentation

Duncan Energy Partners, DEP GP, DEP OLP, Enterprise Products Partners (including EPO and its consolidated subsidiaries) and EPCO and affiliates are under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO. Prior to the drop down of controlling interests in the DEP I and DEP II Midstream Businesses to Duncan Energy Partners, EPO owned these businesses and directed their respective activities for all periods presented (to the extent such businesses were in existence during such periods). Each of the 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. On a standalone basis, Duncan Energy Partners did not own any assets prior to the completion of its initial public offering on February 5, 2007 (February 1, 2007 for financial accounting and reporting purposes).

Our consolidated financial statements include the accounts of Duncan Energy Partners, and prior to the DEP I and DEP II drop down transactions, the assets, liabilities and operations contributed to us by EPO upon the closing of these drop down transactions. Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States. The financial statements of the DEP I and 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 I and 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.

Our consolidated financial statements for the year ended December 31, 2007 reflect the following:

§ Combined financial information of the DEP I Midstream Businesses for the month of January 2007. The results of operations and cash flows of the DEP I Midstream Businesses for this one-month period are allocated to the former owners of these businesses that are under common control with Duncan Energy Partners. On February 5, 2007, these businesses were contributed to Duncan Energy Partners in the DEP I drop down transaction; therefore, the DEP I Midstream Businesses were consolidated subsidiaries of Duncan Energy Partners for the eleven months ended December 31, 2007. For financial accounting and reporting purposes, the effective date of the DEP I drop down transaction is February 1, 2007. EPO's retained ownership in the DEP I Midstream Businesses (following the drop down transaction) is presented in our consolidated financial statements as "Noncontrolling interest in subsidiaries – DEP I Midstream Businesses – Parent."

§ Combined financial information of the DEP II Midstream Businesses for the year ended December 31, 2007. The results of operations and cash flows of the DEP II Midstream Businesses for this twelve-month period are allocated to the former owners of these businesses that are under common control with Duncan Energy Partners.

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 were contributed to Duncan Energy Partners in the DEP II drop down transaction; therefore, the DEP II Midstream Businesses became consolidated subsidiaries of Duncan Energy Partners on this date. 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."

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts balance is determined based on specific identification and estimates of future uncollectible accounts, as appropriate. Our procedure for recording an allowance for doubtful accounts is based on: (i) our historical experience; (ii) the financial stability of our customers; and (iii) the levels of credit granted to customers. In addition, we may also increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and those experiencing other financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure we have recorded sufficient reserves to cover potential losses. The following financial statement schedule presents changes in our allowance for doubtful account balances for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Balance at beginning of period	$ *	$ *	$ 0.4
Charges to expense	--	--	--
Deductions	*	--	(0.4)
Balance at end of period	$ *	$ *	$ *

* Amounts are negligible and less than $0.1 million.

From time to time, we may also establish an allowance for uncollectible natural gas imbalances based on specific identification of accounts. At December 31, 2009 and 2008, our allowance for uncollectible natural gas imbalances was zero. At December 31, 2007, the balance was $5.4 million.

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 I and DEP II Midstream Businesses operated within the EPO cash management program prior to their respective drop down transaction dates of February 1, 2007 and 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 timeframes represent transfers of excess cash from the DEP I and/or 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 Statements 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 I and DEP II Midstream Businesses prior to their respective drop down transaction dates. Following the DEP I and DEP II drop down transactions, 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 for information regarding noncontrolling interest.

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% and we exercise significant 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 Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we would account for the investment using the cost method. 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 legal counsel evaluate such contingent liabilities, and such evaluations inherently involve 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, 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 five percent of total current assets and liabilities, respectively.

Deferred Revenue

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2009 and 2008, deferred revenues totaled $4.5 million and $7.2 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 swaps, forwards and other 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

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, 2009, 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,		
	2009	**2008**	**2007**
Balance at beginning of period	$ 0.6	$ 17.8	$ 20.7
Charges to expense	0.1	0.5	0.3
Deductions (1)	(0.2)	(17.7)	(3.2)
Balance at end of period	$ 0.5	$ 0.6	$ 17.8

(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 Awards

See Note 5 for information regarding our accounting for equity awards.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect: (i) reported amounts of assets and liabilities; (ii) disclosure of contingent assets and liabilities at the date of the financial statements; and (iii) the reported amounts of revenues and expenses during a given period. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable, accrued expenses and other current liabilities 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 at the dates indicated:

	December 31, 2009		December 31, 2008	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 3.9	$ 3.9	$ 13.0	$ 13.0
Accounts receivable	142.0	142.0	156.3	156.3
Financial liabilities:				
Accounts payable and accrued expenses	$ 145.5	$ 145.5	$ 220.0	$ 220.0
Other current liabilities	18.9	18.9	33.3	33.3
Variable-rate revolving credit facility	175.0	175.0	202.0	202.0
Variable-rate term loan	282.3	282.3	282.3	282.3

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis as of January 1 or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, economic obsolescence of plant 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. 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 whenever 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 absence of such data, appropriate valuation techniques. See Note 6 for information regarding impairment charges recorded during 2009.

Impairment Testing for Unconsolidated Affiliate

We evaluate our equity method investment for impairment whenever events or changes in circumstances indicate that there is a potential loss in value of the investment (other than a 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 is primarily applicable 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. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

We recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. We have not taken any uncertain tax positions as defined by the Financial Accounting Standards Board's ("FASB") accounting guidance on income taxes.

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 such volumes. As volumes are delivered out of inventory, the cost of such inventory 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, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the arrangement.

We settle pipeline gas imbalances through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices. As imbalances occur, they may be settled: (i) on a monthly basis; (ii) at the end of the agreement; or (iii) in accordance with industry practice, including negotiated settlements. Certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices.

However, the vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to or received from a customer. Such in-kind deliveries are ongoing and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at 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:

	December 31,	
	2009	**2008**
Natural gas imbalance receivables	$ 9.8	$ 35.7
Natural gas imbalance payables (1)	11.0	43.6

(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. 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 are removed from the accounts and any resulting gain or loss is included in the 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 the assets. Our estimate of depreciation incorporates 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. Under our depreciation policy for midstream energy assets such as the Texas Intrastate System, the remaining economic lives of such assets are limited to the estimated life of the natural resource basins (based on proved reserves at the time of the analysis) from which such assets derive their throughput volumes. 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 the remaining lease term or 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 change our depreciation amounts prospectively. 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 proved reserves of applicable resource basins, if any.

Certain of our plant operations require periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for any planned major maintenance activities.

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. See Note 8 for additional information regarding our property, plant and equipment.

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 accounting standard setting bodies have recently issued the following guidance that will or may affect our future financial statements:

Fair Value Measurements. In January 2010, the FASB issued new guidance to improve disclosures about fair value measurements. This new guidance requires the following:

§ Effective with the first quarter of 2010, additional disclosures will be required regarding the reporting of transfers of fair value information between the three levels of the fair value hierarchy (i.e., Levels 1, 2 and 3).

§ Effective with the first quarter of 2011, companies will need to present purchases, sales, issuances and settlements whose fair values are based on unobservable inputs on a gross basis.

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.

Consolidation of Variable Interest Entities. In June 2009, the FASB amended its consolidation guidance regarding variable interest entities. In general, this new guidance places more emphasis on a qualitative analysis, rather than a purely quantitative approach, in determining which company should consolidate a variable interest entity. Our adoption of this guidance on January 1, 2010 did not have any impact on our consolidated financial statements.

Note 4. Revenue Recognition

We recognize revenue using the following criteria: (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. The following information provides a general description of our revenue recognition policies by segment:

Natural Gas Pipelines & Services

Our Natural Gas Pipelines & Services include approximately 9,400 miles of onshore 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 natural gas marketing activities.

Our natural gas pipelines typically generate revenues from transportation agreements where 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. 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.

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 paid regardless of actual usage 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

Our NGL Pipelines & Services include our (i) NGL marketing activities related to our Big Thicket Gathering System; (ii) NGL pipelines aggregating 1,317 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 obtained 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.

Under our NGL pipeline transportation contracts, revenue is recognized when volumes have been delivered to customers. Revenue from these 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 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. Such fee-based arrangements typically include a base-processing fee (usually stated in cents per gallon) that is contractually subject to adjustment for changes in certain fractionation expenses (e.g. natural gas fuel costs).

Petrochemical Services

Our Petrochemical Services consists of our petrochemical pipelines aggregating 284 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

The following table summarizes the expense we recognized in connection with equity-based awards issued under EPCO's long-term incentive plans for the periods presented (which awards relate to units of affiliates other than Duncan Energy Partners L.P.):

	For Year Ended December 31,		
	2009	2008	2007
Restricted unit awards (1)	$ 1.4	$ 0.7	$ 0.3
Unit option awards (1)	0.2	--	--
Profits interests awards (1)	0.6	0.2	0.2
Total compensation expense	$ 2.2	$ 0.9	$ 0.5

(1) Accounted for as equity-classified awards. The fair value of an equity-classified award is amortized to earnings on a straight-line basis over the requisite service or vesting period.

An allocated portion of the non-cash amortization expense of these awards is charged to us under the administrative services agreement ("ASA") with EPCO. We recognize a non-cash expense for our allocated share of the amortized grant date fair value of such awards, with an offsetting amount recorded in equity. See Note 15 for a general description of the ASA with EPCO. With the exception of certain amounts recorded in connection with EPCO Unit, as defined later in this note, we are not responsible for reimbursing EPCO for any other expenses associated with such awards. Beginning in February 2009, the ASA was amended to provide that we and other affiliates of EPCO will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit. Our reimbursements to EPCO during 2009 in connection with EPCO Unit were $0.1 million.

We have been allocated expense amounts associated with the following long-term incentive plans of EPCO: (i) the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and (ii) the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan").

The 1998 Plan provides for awards of Enterprise Products Partners' 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 units, phantom units, unit appreciation rights ("UARs") and distribution equivalent rights ("DERs"). Up to 7,000,000 of Enterprise Products Partners' common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 652,543 additional common units of Enterprise Products Partners could be issued. All of the awards issued for which we have been allocated expense were in the form of unit options and restricted units.

The 2008 Plan provides for awards of Enterprise Products Partners' 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 units, phantom units, UARs and DERs. Up to 10,000,000 of Enterprise Products Partners' common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 7,865,000 additional common units of Enterprise Products Partners could be issued. All of the awards issued for which we have been allocated expense were in the form of unit options.

DEP Unit Purchase Plan ("EUPP") and
2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan")

On December 10, 2009, the board of directors of our general partner (the "Board") unanimously approved a resolution adopting both the 2010 Plan and the EUPP. The 2010 Plan provides for awards of options to purchase common units, restricted common units, UARs, phantom units and DERs to employees, directors or consultants providing services to us and our subsidiaries. The EUPP provides eligible employees the opportunity to purchase common units at a discount through withholdings from eligible compensation. On December 30, 2009, the action taken by the Board regarding the plans was approved by written consent of a subsidiary of EPO, which held of record approximately 58.6% of our outstanding common units as of that date. Because EPO's subsidiary held a majority of our common units as of December 30, 2009, no other votes were necessary to adopt the plans. In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 500,000 common units in connection with the 2010 Plan and 500,000 common units in connection with the EUPP. The plans became effective on February 11, 2010.

Summary of EPCO long-term incentive plans

The following information is being provided regarding EPCO's long-term incentive plans under which we have or may receive an allocation of expense. In addition to the 1998 Plan and 2008 Plan, EPCO's active long-term incentive plans include the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan"), under which unit options, restricted units and other awards may be issued. EPCO also has other plans under which liability-classified awards may be issued. As of December 31, 2009, we have not been allocated any costs of liability-classified awards and therefore have not included any discussion of such plans 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 Unit Awards

Restricted unit awards allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) once a defined vesting period expires, subject to customary forfeiture provisions. The restrictions on such awards generally lapse four years from the date of grant. The fair value of restricted units 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. As used in the context of Enterprise Products Partners' long-term incentive plans, the term "restricted unit" represents a time-vested unit. Such awards are non-vested until the required service period expires.

The following table summarizes information regarding Enterprise Products Partners' restricted unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2006	1,105,237	$ 24.79
Granted (2)	738,040	$ 30.64
Vested	(4,884)	$ 25.28
Settled or forfeited (3)	(149,853)	$ 23.31
Restricted units at December 31, 2007	1,688,540	$ 27.23
Granted (4)	766,200	$ 30.73
Vested	(285,363)	$ 23.11
Forfeited	(88,777)	$ 26.98
Restricted units at December 31, 2008	2,080,600	$ 29.09
Granted (5)	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 units at December 31, 2009	2,720,882	$ 27.70

(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 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 unit awards issued during 2007 was $22.6 million based on grant date market prices of Enterprise Products Partners' common units ranging from $28.00 to $31.83 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
(3) Reflects the settlement of 113,053 restricted units in connection with the resignation of EPGP's former chief executive officer.
(4) Aggregate grant date fair value of restricted unit awards issued during 2008 was $23.5 million based on grant date market prices of Enterprise Products Partners' common units ranging from $25.00 to $32.31 per unit. An estimated forfeiture rate of 17% was applied to these awards.
(5) Aggregate grant date fair value of restricted unit awards issued during 2009 was $25.5 million based on grant date market prices of Enterprise Products Partners' 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.

On a gross basis, the total unrecognized compensation cost of such awards was $37.9 million at December 31, 2009, of which our share is currently estimated to be $4.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years.

Unit Option Awards

Certain of Enterprise Products Partners' long-term incentive plans provide for the issuance of non-qualified incentive options to purchase a fixed number of its common units. When issued, the exercise price of each option grant may be no less than the market price of the underlying security 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 options, risk-free interest rates, expected distribution yield on Enterprise Products Partners' common units, and expected unit price volatility of its common units. 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 Enterprise Products Partners' historical unit price volatility and distribution yield over a period equal to the expected life of the option.

During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, Enterprise Products Partners 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 Products Partners.

The following table presents unit option activity under the EPCO plans for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2006	2,416,000	$ 23.32		
Granted (2)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (3)	(740,000)	24.62		
Outstanding at December 31, 2007	2,315,000	26.18		
Granted (4)	795,000	30.93		
Exercised	(61,500)	20.38		
Forfeited	(85,000)	26.72		
Outstanding at December 31, 2008	2,963,500	27.56		
Granted (5)	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		
Outstanding at December 31, 2009 (6)	3,825,920	26.52	4.6	$ 2.8
Options exercisable at:				
December 31, 2007	335,000	$ 22.06	4.0	$ 3.3
December 31, 2008	548,500	$ 21.47	4.1	$ --
December 31, 2009 (6)	447,500	$ 25.09	4.8	$ 2.8

(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 2007 was $2.4 million based on the following assumptions: (i) a weighted-average grant date market price of Enterprise Products Partners' common units of $30.63 per unit; (ii) expected life of options of 7.0 years; (iii) weighted-average risk-free interest rate of 4.8%; (iv) weighted-average expected distribution yield on Enterprise Products Partners' common units of 8.4%; and (v) weighted-average expected unit price volatility on Enterprise Products Partners' common units of 23.2%.

(3) Includes the settlement of 710,000 options in connection with the resignation of EPGP's chief executive officer.

(4) 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 Products Partners' 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 Products Partners' common units of 7.0%; and (v) an expected unit price volatility on Enterprise Products Partners' common units of 19.8%. An estimated forfeiture rate of 17.0% was applied to awards granted during 2008.

(5) 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 Products Partners' 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 Products Partners' common units of 9.4%; and (v) weighted-average expected unit price volatility on Enterprise Products Partners' common units of 57.4%. An estimated forfeiture rate of 17.0% was applied to awards granted during 2009.

(6) Enterprise Products Partners was committed to issue 3,825,920 and 2,963,500 of Enterprise Products Partners' common units at December 31, 2009 and 2008, respectively, if all outstanding options awarded (as of these dates) were exercised. Of the option awards outstanding at December 31, 2009, an additional 410,000, 712,280, 736,000 and 1,520,140 are exercisable in 2010, 2012, 2013 and 2014, respectively.

On a gross basis, the total unrecognized compensation cost of such awards was $7.3 million at December 31, 2009, of which our share is currently estimated to be $0.6 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.9 years.

Profits Interests Awards

As long-term incentive arrangements, EPCO has granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in several limited partnerships (the "Employee Partnerships"), all of which are privately held affiliates of EPCO. Profits interests awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which our named executive officers participate own either units of Enterprise GP Holdings or Enterprise Products Partners or a combination of both. The profits interests awards are subject to customary forfeiture provisions.

Each Employee Partnership has a single Class A limited partner, which is a privately held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market. In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the partnership agreement) on its investment (or "Capital Base") in the Employee Partnership and residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership assets having a fair market value equal to the Class A limited partner's Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest and are a factor of the appreciation in value of the partnership's assets since its formation date.

The grant date fair value of each Employee Partnership is based on (i) the estimated value of the remaining assets, as determined using a Black-Scholes option pricing model, that would be distributed to the Class B limited partners upon dissolution of the Employee Partnership and (ii) the value, based on a discounted cash flow analysis using appropriate discount rates, of the residual quarterly cash amounts that the Class B limited partners are expected to receive over the life of the Employee Partnership.

The following table summarizes key elements of each Employee Partnership as of December 31, 2009. As used in the table in reference to the description of assets, "EPE" means Enterprise GP Holdings L.P. and "EPD" means Enterprise Products Partners L.P.

Employee Partnership	Description of Assets	Initial Class A Capital Base	Class A Partner Preferred Return	Liquidation Date (1)	Grant Date Fair Value of Awards	Unrecognized Compensation Cost
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725%	February 2016	$21.5 million	$12.1 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725%	February 2016	$0.4 million	$0.3 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	February 2016	$42.8 million	$30.8 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2016	$6.5 million	$5.3 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	February 2016	$8.1 million	$6.5 million

(1) The liquidation date may be accelerated for change of control and other events as described in the underlying partnership agreements.

The total unrecognized compensation cost of the profits interests awards was $55.0 million at December 31, 2009 of which our share is currently estimated to be $3.8 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 6.1 years.

In December 2009, the expected liquidation date for each Employee Partnership was extended to February 2016. This modification follows 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 are intended to align the interests of the employee partners of the Employee Partnerships with the long-term interests of EPCO and other unitholders in the relevant underlying publicly traded partnerships, which also hold indirectly a significant ownership interest in both us and our subsidiaries.

The following table presents the impact of modifications (e.g., extension of liquidation dates) and other changes on the aggregate grant date fair value (on an unallocated basis) of the Employee Partnerships for the periods presented.

	For Year Ended December 31,		
	2009	2008	2007
Aggregate grant date fair values at beginning of period	$ 64.6	$ 35.4	$ 12.8
New Employee Partnership grants (1,2)	--	14.6	23.0
Award modifications	19.5	15.0	--
Other adjustments, primarily forfeiture and regrant activity (2)	(4.8)	(0.4)	(0.4)
Aggregate grant date fair value at end of period	$ 79.3	$ 64.6	$ 35.4

(1) EPE Unit III was formed in 2007 and EPCO Unit and Enterprise Unit were formed in 2008.
(2) TEPPCO Unit L.P. and TEPPCO Unit II L.P. were formed during 2008 and dissolved during 2009.

The following table summarizes the assumptions used in deriving that portion of the estimated grant date fair value for each Employee Partnership using a Black-Scholes option pricing model:

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 course of our normal business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain identifiable and anticipated 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 futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they 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 ("OCI") 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 things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is probable of not occurring is immediately recognized in earnings.

Interest Rate Derivative Instruments

We utilize interest rate swaps to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at December 31, 2009, all of which were designated as hedging instruments under the FASB's derivative and hedging guidance:

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	0.25% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months.

Cash flow hedges fix the interest rate paid on floating rate debt with the difference between the floating rate and fixed rate being recorded as an increase/decrease to interest expense. This combined activity resulted in an increase of interest expense of $6.5 million and $2.0 million, respectively, for 2009 and 2008.

For information regarding consolidated fair value amounts and gains and losses on interest rate derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 6.

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 the absolute notional amount of our commodity derivative instruments outstanding at December 31, 2009:

Derivative Purpose	Volume		Accounting
	Current	Long-Term	Treatment
Derivatives not designated as hedging instruments:			
Acadian Gas:			
Natural gas risk management activities	2.2 Bcf	n/a	Mark-to-market

At December 31, 2009, none of our derivative instruments met hedge accounting requirements; therefore, they are accounted for using mark-to-market accounting.

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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.

Historically, the use of commodity derivative instruments was governed by policies established by the general partner of Enterprise Products Partners. Our general partner now 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.

For information regarding consolidated fair value amounts and gains and losses on commodity derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 6.

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, 2009, we did not have any derivative instruments 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, 2009		December 31, 2008		December 31, 2009		December 31, 2008	
	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	$ 5.5	Other current liabilities	$ 5.9
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	3.9
Total derivatives designated as hedging instruments		$ --		$ --		$ 5.5		$ 9.8
Derivatives not designated as hedging instruments:								
Commodity derivatives	Other current assets	$ 0.1	Other current assets	$ 1.9	Other current liabilities	$ 0.1	Other current liabilities	$ 2.0
Total derivatives not designated as hedging instruments		$ 0.1		$ 1.9		$ 0.1		$ 2.0

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Statements of Consolidated Operations for the periods presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in OCI on Derivative (Effective Portion) For the Twelve Months Ended December 31, 2009	2008
Interest rate	$ (2.5)	$ (8.0)
Commodity	--	(0.7)
Total	$ (2.5)	$ (8.7)

Derivatives in Cash Flow Hedging Relationships	Location of Loss Reclassified from AOCI into Income (Effective Portion)	Amount of Loss Reclassified from AOCI into Income (Effective Portion) For the Twelve Months Ended December 31, 2009	2008
Interest rate	Interest expense	$ (6.6)	$ (2.0)
Commodity	Operating Revenue	--	(0.7)
Total		$ (6.6)	$ (2.7)

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

* Indicates that amounts are negligible and less than $0.1 million.

Over the next twelve months, we expect to reclassify $5.4 million of AOCI attributable to interest rate derivative instruments into earnings as an increase to interest expense, based on the current level of interest rates.

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 Amount For the Twelve Months Ended December 31, 2009	2008
Commodity derivatives	Revenue	$ (0.6)	$ 0.7
Total		$ (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 extent 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 financial 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 are based on observable price quotes for similar products and locations. Our interest rate derivatives are 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 inputs are typically used in connection with internally developed valuation methodologies where management makes its 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, 2009, 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 measured on a recurring basis at the dates indicated. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value assets and liabilities, in addition to their placement within the fair value hierarchy levels.

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

* Indicates that amounts are negligible and less than $0.1 million.

	At December 31, 2008		
	Level 1	Level 2	Total
Financial assets:			
Commodity derivative instruments	$ *	$ 1.9	$ 1.9
Financial liabilities:			
Commodity derivative instruments	$ 1.9	$ 0.1	$ 2.0
Interest rate derivative instruments	--	9.8	9.8
Total derivative liabilities	$ 1.9	$ 9.9	$ 11.8

* Indicates that amounts are negligible and less than $0.1 million.

Nonfinancial Assets and Liabilities

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). The following table presents the estimated fair value of certain assets carried on our Consolidated Balance Sheet by caption for which a nonrecurring change in fair value has been recorded during the year ended December 31, 2009:

	Level 3	Impairment Charges
Property, plant and equipment	$ 1.8	$ 4.2

Using appropriate valuation techniques, we adjusted the carrying value of certain of our Natural Gas Pipelines and Services segment assets when we recorded a non-cash asset impairment charge of $3.3 million due to the cancellation of a compressor station project on our Texas Intrastate System. We also adjusted the carrying value of certain pipeline segments of the Texas Intrastate System to fair value during 2009. Anticipated abandonment activities related to a portion of this system led to a non-cash impairment charge of $0.9 million. These impairment charges are reflected in operating costs and expenses for the year ended December 31, 2009.

Note 7. Inventories

Our inventory amounts were as follows at the dates indicated:

	December 31, 2009	December 31, 2008
Working inventory (1)	$ 4.4	$ 18.3
Forward sales inventory (2)	6.1	9.7
Total inventory	$ 10.5	$ 28.0

(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, 2009 and 2008, the value of natural gas held in inventory for operational system balancing was $2.8 million and $15.5 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 and generally affect our segment operating results in the following manner:

§ Write-downs of natural gas inventories are recorded as an expense related to our natural gas pipeline operations within our Natural Gas Pipelines & Services business segment.

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,		
	2009	2008	2007
Cost of sales (1)	$ 490.0	$ 1,122.4	$ 811.4
LCM adjustments	*	1.8	0.3

(1) Cost of sales is included in operating costs and expenses, as presented on our Statements of Consolidated Operations. The fluctuation in this amount year-to-year is primarily due to changes in natural gas prices.
* We recognized nominal LCM adjustments for the year ended December 31, 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, 2009	At December 31, 2008
Plant and pipeline facilities (1)	3-45(4)	$ 4,767.0	$ 4,175.0
Underground storage wells and related assets (2)	5-35(5)	432.5	407.9
Transportation equipment (3)	3-10	11.3	10.3
Land		27.8	23.9
Construction in progress		233.6	459.0
Total		5,472.2	5,076.1
Less accumulated depreciation		922.6	745.9
Property, plant and equipment, net		$ 4,549.6	$ 4,330.2

(1) Includes natural gas, NGL and petrochemical pipelines, NGL fractionation plants, office furniture and equipment, buildings, and related assets.
(2) Underground storage facilities include underground 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 life of major components of this category is: pipelines, 18-45 years (with some equipment at 5 years); office furniture and equipment, 3-20 years; and buildings 20-35 years.
(5) In general, the estimated useful life of underground storage facilities is 20-35 years (with some components at 5 years).

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, we increased the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System as of January 1, 2008.

These revisions extended the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting volumes for these assets have increased their estimated useful life. There were no changes to the residual values of these assets. These revisions prospectively reduced our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. As a result of this change in estimate, depreciation expense decreased by approximately $20.0 million for the year ended December 31, 2008. The reduction in depreciation expense increased operating income and net income by equal amounts from what they would have been absent the change. Depreciation expense for the years ended December 31, 2009, 2008 and 2007 was $176.7 million, $158.5 million and $163.4 million, respectively.

Asset Retirement Obligations

We have recorded conditional AROs in connection with certain right-of-way agreements, leases and regulatory requirements. Conditional AROs are obligations in which the timing and/or amount of settlement are uncertain. None of our assets are legally restricted for purposes of settling AROs.

The following table presents information regarding our AROs since December 31, 2007.

ARO liability balance, December 31, 2007	$	8.1
Liabilities incurred		1.3
Liabilities settled		(5.3)
Accretion expense		0.3
Revisions in estimated cash flows		0.2
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

The increase in our ARO liability balance during 2009 primarily reflects revised estimates of the cost to comply with regulatory abandonment obligations associated with our TPC Offshore gathering system, a component of the Texas Intrastate System located offshore in the Gulf of Mexico. Net property, plant and equipment at December 31, 2009 and 2008 includes $5.5 million and $1.1 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents forecasted accretion expense associated with our ARO's for the years presented:

2010	2011	2012	2013	2014
$ 0.7	$ 0.6	$ 0.6	$ 0.7	$ 0.8

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 financial investment in Evangeline using the equity method. Our investment in Evangeline is classified within our Natural Gas Pipelines & Services business segment.

Evangeline owns a 27-mile natural gas pipeline system extending from Taft, Louisiana to Westwego, Louisiana that connects three electric generation stations owned by Entergy Louisiana ("Entergy"). Evangeline's most significant contract is a 21-year 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 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, creating an essentially fixed monthly net sales 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 begins the earlier of July 1, 2010 or upon the payment in full of Evangeline's Series B notes and terminates on December 31, 2012. We cannot ascertain when, or if, Entergy will exercise this purchase option. 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 distributions from Evangeline since we acquired our interest in Evangeline in April 2001. The trust indenture governing Evangeline's Series B notes places restrictions on the payment of distributions to Evangeline's partners. Evangeline is permitted to pay distributions if, after giving effect to the distribution, no default or event of default has occurred and is continuing, funds held in its restricted cash account equals or exceeds its debt service requirement and the holders of the Series B notes are cash secured. Our share of undistributed earnings of Evangeline totaled approximately $3.6 million at December 31, 2009. See Note 11 for a description of Evangeline's outstanding debt obligations.

Summarized financial information of Evangeline is presented below.

	At December 31, 2009	At December 31, 2008
BALANCE SHEET DATA:		
Current assets	$ 24.4	$ 33.5
Property, plant and equipment, net	3.2	4.2
Other assets	13.5	17.5
Total assets	$ 41.1	$ 55.2
Current liabilities	$ 10.6	$ 24.2
Other liabilities	17.7	20.4
Consolidated equity	12.8	10.6
Total liabilities and consolidated equity	$ 41.1	$ 55.2

	For the Year Ended December 31, 2009	2008	2007
INCOME STATEMENT DATA:			
Revenues	$ 164.5	$ 371.8	$ 272.9
Operating income	3.7	7.2	6.3
Net income	2.2	1.8	0.4

Note 10. Intangible Assets and Goodwill

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

	At December 31, 2009			At December 31, 2008		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 24.6	$ (8.9)	$ 15.7	$ 24.6	$ (6.4)	$ 18.2
Contract based intangibles	40.8	(24.7)	16.1	40.8	(20.1)	20.7
Natural Gas Pipelines & Services:						
Customer relationship intangibles	21.0	(9.0)	12.0	21.0	(7.6)	13.4
Total all segments	$ 86.4	$ (42.6)	$ 43.8	$ 86.4	$ (34.1)	$ 52.3

Due to the renewable nature of the underlying contracts, we amortize the Mont Belvieu storage contracts on a straight-line basis over the estimated 27 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 2.3 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.

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.

The following table presents amortization expense attributable to our intangible assets (by segment) for the periods indicated:

	For the Year Ended December 31,		
	2009	2008	2007
NGL Pipelines & Services	$ 7.1	$ 7.6	$ 5.5
Natural Gas Pipelines & Services	1.4	1.5	1.7
Total segments	$ 8.5	$ 9.1	$ 7.2

Based on information currently available, the following table presents an estimate of future amortization expense associated with our intangible assets at December 31, 2009:

	For the Year Ended December 31,				
	2010	2011	2012	2013	2014
NGL Pipelines & Services	$ 6.7	$ 6.4	$ 2.9	$ 1.7	$ 1.5
Natural Gas Pipelines & Services	1.3	1.2	1.1	1.0	0.9
Total segments	$ 8.0	$ 7.6	$ 4.0	$ 2.7	$ 2.4

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. Goodwill is not amortized; however, it is subject to annual impairment testing at the beginning of each fiscal year. Our goodwill at December 31, 2009 and 2008 was $4.9 million and represents an allocation to the DEP II Midstream Businesses of the goodwill recorded by Enterprise Products Partners 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, 2009	At December 31, 2008
Revolving Credit Facility, variable rate, due February 2011	$ 175.0	$ 202.0
Term Loan Agreement, variable rate, due December 2011	282.3	282.3
Total principal amount of long-term debt obligations	$ 457.3	$ 484.3

Revolving Credit Facility

We have, in place, a $300.0 million Revolving Credit Facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline Loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. We may make up to two requests for one-year extensions of the maturity date (subject to certain restrictions).

At the closing of our initial public offering, we made an initial draw of $200.0 million under this facility to fund the $198.9 million cash distribution to EPO in connection with the DEP I drop down transaction (see Note 1) and the remainder to pay debt issuance costs. At December 31, 2009, the principal balance outstanding under this facility was $175.0 million. After taking into account amounts outstanding and the effect of the bankruptcy of one of the lenders, at December 31, 2009, we had the ability to borrow up to $121.7 million under our Revolving Credit Facility. We have hedged a significant portion of our variable interest rate exposure under this loan agreement; however, these hedges expire in September 2010. See Note 6 for information regarding our interest rate hedging activities.

We can increase the borrowing capacity under our Revolving Credit Facility, without consent of the lenders, by an amount not to exceed $150.0 million, by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased.

As defined in the credit agreement, variable interest rates charged under this facility may bear interest at either, (i) a Eurodollar rate plus an applicable margin or (ii) a Base Rate. The Base Rate is the higher of (i) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate or (ii) 0.5% per annum above the Federal Funds Rate in effect on such date.

The credit facility 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.

Term Loan Agreement

In April 2008, we entered into a standby term loan agreement consisting of commitments for up to $300.0 million under the Term Loan Agreement. Subsequently, commitments under the Term Loan Agreement decreased to $282.3 million due to bankruptcy of one of the lenders. On December 8, 2008, we borrowed the full amount available under this loan agreement to fund the cash consideration due EPO in connection with the DEP II drop down transaction (see Note 1).

We may prepay loans under the Term Loan Agreement at any time, subject to prior notice in accordance with the credit agreement. Loans may also be payable earlier in connection with an event of default.

Loans under the Term Loan Agreement bear interest of the type specified in the applicable borrowing request, and consist of either Alternate Base Rate loans or Eurodollar loans. 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.

Covenants

We were in compliance with the covenants of our debt agreements at December 31, 2009.

Information Regarding Variable Interest Rates Paid

The following table presents the weighted-average interest rate paid on our consolidated variable-rate debt obligations during the year ended December 31, 2009.

	Weighted-average interest rate paid
Revolving Credit Facility, variable rate, due February 2011	1.4754%
Term Loan Agreement, variable rate, due December 2011	1.1486%

Evangeline Joint Venture Debt Obligation

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

	At December 31, 2009	At December 31, 2008
9.9% fixed interest rate senior secured notes due December 2010 (“Series B” notes):		
Current portion of debt – due December 31, 2010	$ 3.2	$ 5.0
Long-term portion of debt	--	3.2
$7.5 million subordinated note payable to an affiliate of other co-venture participant (“LL&E Note”)	7.5	7.5
Total joint venture debt principal obligation	$ 10.7	$ 15.7

The Series B notes are collateralized by Evangeline’s: (i) property, plant and equipment; (ii) proceeds from its Entergy natural gas sales contract (see Note 9); and (iii) a debt service reserve requirement. Scheduled principal repayments on the Series B notes are $5.0 million annually through December 2009, with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains certain financial and other customary affirmative and negative covenants such as the maintenance of certain financial ratios. Evangeline was in compliance with such covenants during the year ended December 31, 2009.

The LL&E Note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have 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, 2009 and 2008 were 1.59% and 3.62%, respectively. At December 31, 2009 and 2008, the amount of accrued but unpaid interest on the LL&E Note was approximately $10.2 million and $9.8 million, respectively.

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 the other rights or privileges available to them under our Amended and Restated Agreement of Limited Partnership (as amended from time to time, the “Partnership Agreement”).

Capital accounts, as defined in our Partnership Agreement, are maintained by us for our general partner and our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our financial statements. Earnings and cash distributions are allocated to our partners in accordance with their respective percentage interests.

In February 2007, we completed our initial public offering of 14,950,000 common units (including an overallotment of 1,950,000 common units), which generated net cash proceeds of $290.5 million. As consideration for the DEP I drop down transaction (see Note 1), we distributed $260.6 million of the net cash proceeds from our IPO plus $198.9 million in borrowings and a net 5,351,571 common units to EPO. We used $38.5 million of the overallotment proceeds to redeem 1,950,000 of the 7,301,571 common units we originally issued to EPO in connection with the DEP I drop down transaction, resulting in a final amount of 5,351,571 common units beneficially owned by EPO.

Class B Units

Our limited partners' equity account balance at December 31, 2008 reflected the issuance to EPO of 37,333,887 Class B units, which were used along with proceeds borrowed under the Term Loan Agreement to acquire the DEP II Midstream Businesses 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 $1 billion in debt and equity securities for general partnership purposes. After taking into account a June 2009 equity offering made under this registration statement (see below), 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 underwritten 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.

In December 2009, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate 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 did not issue any common units under the DRIP during the year ended December 31, 2009.

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 and a long-term incentive plan. These plans became effective on February 11, 2010. See Note 5 for additional information.

Unit History

The following table details changes in our outstanding common units since our initial public offering on February 5, 2007:

	Limited Partner Units	Treasury Units	Total Outstanding Units
Activity on February 5, 2007:			
Common units originally issued to EPO in connection with the DEP I drop down transaction	7,301,571	--	7,301,571
Common units issued in connection with our IPO	14,950,000	--	14,950,000
Redemption of common units using proceeds from IPO overallotment	(1,950,000)	--	(1,950,000)
Common units outstanding, December 31, 2007	20,301,571	--	20,301,571
Common units sold to EPO in connection with the DEP II drop down transaction	41,529	--	41,529
Common units outstanding, December 31, 2008	20,343,100	--	20,343,100
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

Distributions

Our partnership agreement requires us to distribute all of our available cash (as defined in our 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 our initial distribution rate or at any other rate. Our general partner has no incentive distribution rights. The following table presents the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units with respect to each quarterly period since our IPO.

	Cash Distribution History		
	Per Unit	Record Date	Payment Date
2008			
1st Quarter	0.4100	April 30, 2008	May 7, 2008
2nd Quarter	0.4200	July 31, 2008	August 7, 2008
3rd Quarter	0.4200	October 31, 2008	November 12, 2008
4th Quarter (1)	0.4275	January 30, 2009	February 9, 2009
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

(1) We issued 37.3 million Class B units in connection with the DEP II drop down. The Class B units received a cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008, which represented the regular quarterly distribution pro-rated for the 24-day period from December 8, 2008, the closing date of the DEP II drop down transaction, to December 31, 2008. These units automatically converted on a one-for-one basis to common units on February 1, 2009.

Accumulated Other Comprehensive Loss

Our AOCI balance, which was related to interest rate derivative instruments, reflected losses of $5.4 million and $9.6 million at December 31, 2009 and December 31, 2008, respectively.

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.

DEP I Midstream Businesses – Parent

The DEP I Midstream Businesses allocate their net income (or loss) to us and EPO based on our respective sharing ratios, which are currently 66% to us and 34% to EPO. In deriving the net income (or loss) of Mont Belvieu Caverns to be allocated between us and EPO, certain special allocations are required as follows:

§ EPO is allocated all operational measurement gains and losses; and

§ EPO is allocated 100% of the depreciation expense related to capital projects that it has fully funded.

Distributions paid to us and EPO by the DEP I Midstream Businesses are in accordance with each owner's respective sharing ratio. In general, contributions made by us and EPO to the DEP I Midstream Businesses are in accordance with the previously noted sharing ratios. However, special funding arrangements exist under the terms of an Omnibus Agreement and the limited liability company agreement of Mont Belvieu Caverns (the "Caverns LLC 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 and $32.5 million in connection with these capital projects during the years ended December 31, 2009 and 2008, respectively. The majority of these contributions related to funding Phase II expansion costs of the South Texas NGL pipeline. This project 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.

EPO made cash contributions of $16.6 million and $99.5 million under the Caverns LLC Agreement during the years ended December 31, 2009 and 2008, respectively, to fund 100% of certain storage-related projects sponsored by EPO's NGL marketing activities. We elected to not participate in such projects. EPO is not expected to receive an increased allocation of earnings or cash flows as a result of these contributions to Mont Belvieu Caverns. Additional contributions of approximately $32.7 million are expected from EPO to fund such projects in 2010. The constructed assets will be the property of Mont Belvieu Caverns.

In accordance with the Caverns LLC Agreement, 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 gains and losses associated with our Mont Belvieu storage complex. Such amounts are included in operating costs and expenses and gross operating margin. However, these operational measurement gains and losses do not impact net income attributable to Duncan Energy Partners since they are allocated to EPO. We have not established a reserve for operational measurement losses on our balance sheet.

The following table presents our calculation of "Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent" for the years ended December 31, 2009, 2008 and 2007.

	For the Year Ended December 31,		
	2009	2008	2007
Total net income of DEP I Midstream Businesses, prior to special allocations	$ 68.0	$ 56.4	$ 45.4
Multiplied by Parent 34% interest in net income	x 34%	x 34%	x 34%
Parent 34% interest in net income, prior to special allocations	23.1	19.2	15.5
Add (deduct) operational measurement gain (loss) allocated to Parent	(1.7)	(6.8)	4.5
Less depreciation expense related to fully funded projects allocated to Parent	(6.1)	(1.0)	--
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	$ 15.3	$ 11.4	$ 20.0

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, 2009 and 2008:

December 31, 2007 balance	$ 355.2
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	11.4
Contributions made by EPO to South Texas NGL and Mont Belvieu Caverns in connection with the following agreements:	
Caverns LLC Agreement	88.1
Omnibus Agreement	31.4
Other contributions made by EPO to the DEP I Midstream Businesses	36.5
Cash distributions paid to EPO by the DEP I Midstream Businesses	(44.2)
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
Cash distributions paid to EPO by the DEP I Midstream Businesses	(25.3)
December 31, 2009 balance	$ 487.3

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 22.6% of the equity of 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.

Generally, 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 distributed 98% to EPO and 2% to us.

The initial annualized return rate for 2009 was 11.85%, and was determined by EPO and us 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 will be 12.087%. 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. At December 8, 2008 and December 31, 2009, our Distribution Base was $730.0 million. EPO's Distribution Base was $452.1 million and $817.9 million at December 8, 2008 and December 31, 2009, respectively. The increase in EPO's Distribution Base is the result of its decision to fund 100% of the expansion capital projects of the DEP II Midstream Businesses since December 8, 2008. We have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, although 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 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. 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.

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.

	DEP		EPO
Total net income of DEP II Midstream Businesses		$ 0.5	$ 0.5
Multiplied by each owner's Percentage Interest		22.6%	77.4%
Base earnings allocation to each owner		0.1	0.4
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 income attributable to Duncan Energy Partners		$ 4.5	
Net loss attributable to EPO as noncontrolling interest			$ (4.0)

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

		DEP	EPO
Total net loss of DEP II Midstream Businesses		$ (0.5)	$ (0.5)
Multiplied by each owner's Percentage Interest		22.6%	77.4%
Base earnings allocation to each owner		(0.1)	(0.4)
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 income attributable to Duncan Energy Partners		$ 60.1	
Net loss attributable to EPO as noncontrolling interest			$ (60.6)

We and EPO received $86.5 million and $29.8 million, respectively, in cash distributions from the DEP II Midstream Businesses for the twelve months ended December 31, 2009. The $86.5 million (or, approximately, $21.6 million each quarter) received by us with respect to 2009 represents the annualized return rate for 2009 of 11.85% 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 2009, it was entitled to $83.4 million of Tier II distributions, of which it received only $29.8 million. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to 2009.

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, 2009 and 2008. Amounts are for the period from the closing of the drop down transaction to December 31, 2009.

Retention by Parent of ownership interest in DEP II Midstream Businesses on December 8, 2008	$ 2,595.5
Net loss attributable to noncontrolling interest – DEP II Midstream Businesses – Parent	(4.0)
Contributions by EPO in connection with expansion cash calls	21.3
Distributions to noncontrolling interest of subsidiary operating cash flows	(0.8)
Other general cash contributions from noncontrolling interest	1.0
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

For additional information regarding our agreements with EPO in connection with the DEP II drop down transaction, see "Significant Relationships and Agreements 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 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 management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash consolidated 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 consolidation. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interests.

Segment revenues include intersegment and intrasegment transactions. Our consolidated revenues reflect the elimination of all material intercompany transactions.

We include equity earnings from Evangeline in our measurement of segment gross operating margin and operating income. Our equity investments in midstream energy operations such as those conducted by Evangeline are a vital component of our long-term business strategy and important to the operations of Acadian Gas. This method of operation enables us to achieve favorable economies of scale relative to our level of investment and also lowers our exposure to business risks compared to the profile we would have on a stand-alone basis. Our equity investee is within the same industry as our consolidated operations, thus we believe treatment of earnings from our equity method investee 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 (which are 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. Consolidated 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 the Year Ended December 31,		
	2009	2008	2007
Revenues	$ 979.3	$ 1,598.1	$ 1,220.3
Less: Operating costs and expenses	(908.3)	(1,512.8)	(1,171.0)
Add: Equity in income of Evangeline	1.1	0.9	0.2
Depreciation, amortization and accretion in operating costs and expenses (1)	186.3	167.3	175.3
Impairment charge included in operating costs and expenses	4.2	--	--
Gain on asset sales and related transactions in operating costs and expenses	(0.5)	(0.5)	(0.1)
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on the Statements of Consolidated Cash Flows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents a reconciliation of total segment gross operating margin to operating income and further to GAAP net income for the periods noted:

	For the Year Ended December 31,		
	2009	2008	2007
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses (1)	(186.3)	(167.3)	(175.3)
Impairment charge included in operating costs and expenses	(4.2)	--	--
Gain on asset sales and related transactions in operating costs and expenses	0.5	0.5	0.1
General and administrative costs	(11.2)	(18.3)	(13.1)
GAAP operating income	60.9	67.9	36.4
Other expense, net	(13.8)	(11.5)	(8.6)
Provision for income taxes	(1.3)	(1.1)	(4.2)
GAAP net income	$ 45.8	$ 55.3	$ 23.6

(1) Amount is a component of “Depreciation, amortization and accretion” as presented on the Statements of Consolidated Cash Flows.

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

	Natural Gas Pipelines & Services	NGL Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:					
Year ended December 31, 2009	$ 390.2	$ 88.2	$ 13.6	$ --	$ 492.0
Year ended December 31, 2008	773.1	69.1	14.2	--	856.4
Year ended December 31, 2007	685.2	59.7	14.4	--	759.3
Revenues from related parties:					
Year ended December 31, 2009	348.5	138.8	--	--	487.3
Year ended December 31, 2008	582.2	159.5	--	--	741.7
Year ended December 31, 2007	323.2	134.8	3.0	--	461.0
Total revenues:					
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
Year ended December 31, 2007	1,008.4	194.5	17.4	--	1,220.3
Equity in income of Evangeline:					
Year ended December 31, 2009	1.1	--	--	--	1.1
Year ended December 31, 2008	0.9	--	--	--	0.9
Year ended December 31, 2007	0.2	--	--	--	0.2
Gross operating margin by individual business segment and in total:					
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
Year ended December 31, 2007	122.5	87.9	14.3	--	224.7
Segment assets:					
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
At December 31, 2007	2,716.6	731.5	89.6	257.3	3,795.0
Property, plant and equipment:					
At December 31, 2009	3,318.8	913.8	83.3	233.7	4,549.6
At December 31, 2008	2,887.5	897.1	86.6	459.0	4,330.2
At December 31, 2007	2,693.8	697.3	89.6	257.3	3,738.0
Investment in Evangeline: (see Note 9)					
At December 31, 2009	5.6	--	--	--	5.6
At December 31, 2008	4.5	--	--	--	4.5
At December 31, 2007	3.5	--	--	--	3.5
Intangible assets:					
At December 31, 2009	12.0	31.8	--	--	43.8
At December 31, 2008	13.4	38.9	--	--	52.3
At December 31, 2007	14.9	33.7	--	--	48.6
Goodwill:					
At December 31, 2009	4.4	0.5	--	--	4.9
At December 31, 2008	4.4	0.5	--	--	4.9
At December 31, 2007	4.4	0.5	--	--	4.9

Our consolidated revenues were earned in the United States. Our operations are located in Texas and Louisiana. Our largest third-party customer was Exxon Mobil, which accounted for 7.5%, 10.0% and 7.6% of our consolidated revenues in 2009, 2008 and 2007, respectively. The majority of our revenues from Exxon Mobil is derived from the sale and transportation of natural gas and is also presented in our Natural Gas Pipelines & Services business segment. Sales to Exxon Mobil totaled $73.4 million, $159.2 million and $93.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

	For the Year Ended December 31,		
	2009	2008	2007
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 460.2	$ 1,100.2	$ 794.1
Natural gas transportation services	263.2	246.7	212.8
Natural gas storage services	15.3	8.4	1.5
Total	$ 738.7	$ 1,355.3	$ 1,008.4
NGL Pipelines & Services:			
Sales of NGLs	$ 35.0	$ 47.9	$ 40.3
Sales of other products	11.3	15.0	10.8
NGL and petrochemical storage services	104.9	87.4	68.9
NGL fractionation services	29.5	32.4	30.3
NGL transportation services	43.8	43.6	42.5
Other services	2.5	2.3	1.7
Total	$ 227.0	$ 228.6	$ 194.5
Petrochemical Services:			
Propylene transportation services	$ 13.6	$ 14.2	$ 17.4
Total consolidated revenues	$ 979.3	$ 1,598.1	$ 1,220.3
Consolidated cost and expenses			
Operating costs and expenses:			
Cost of natural gas and NGL sales	$ 479.7	$ 1,123.9	$ 815.8
Depreciation, amortization and accretion	186.3	167.4	175.3
Gain on asset sales and related transactions	(0.5)	(0.5)	(0.1)
Other operating expenses	242.8	222.0	180.0
General and administrative costs	11.2	18.3	13.1
Total consolidated costs and expenses	$ 919.5	$ 1,531.1	$ 1,184.1

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 prices rise.

Note 15. Related Party Transactions

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

	For the Year Ended December 31, 2009	2008	2007
Revenues:			
Revenues from EPO:			
Sales of natural gas	$ 141.9	$ 177.3	$ 29.6
Natural gas transportation services	56.4	51.5	35.8
Natural gas storage services	2.6	0.9	--
Sales of NGLs	33.7	52.9	41.2
NGL and petrochemical storage services	36.2	35.2	28.9
NGL fractionation services	32.0	29.7	30.3
NGL transportation services	28.6	30.4	27.6
Other services	--	--	3.0
Sales of natural gas – Evangeline	155.5	362.9	264.2
Natural gas transportation services – Energy Transfer Equity	0.1	0.9	0.4
NGL and petrochemical storage services – Energy Transfer Equity	0.3	--	--
Total related party revenues	$ 487.3	$ 741.7	$ 461.0
Operating costs and expenses:			
EPCO administrative services agreement	$ 85.8	$ 72.1	$ 63.7
Expenses with EPO:			
Purchases of natural gas	52.1	229.9	29.1
Operational measurement losses (gains)	1.7	6.8	(4.5)
Other expenses with EPO	16.4	18.4	7.4
Purchases of natural gas – Nautilus	1.7	10.3	3.5
Expenses with Energy Transfer Equity:			
Purchases of natural gas	5.7	7.3	5.6
Operating cost reimbursements for shared facilities	(3.4)	(2.8)	(1.7)
Other expenses with Energy Transfer Equity	(0.7)	3.1	1.1
Other related party expenses, primarily with Evangeline	--	--	0.1
Total related party operating costs and expenses	$ 159.3	$ 345.1	$ 104.3
General and administrative costs:			
EPCO administrative services agreement	$ 10.9	$ 15.7	$ 11.5
Other related party general and administrative costs	--	(0.8)	(0.1)
Total related party general and administrative costs	$ 10.9	$ 14.9	$ 11.4

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

	December 31, 2009	December 31, 2008
Accounts receivable – related parties		
EPO and affiliates (1)	$ 54.3	$ 2.3
Energy Transfer Equity and affiliates	0.2	0.9
Other	--	0.1
Total	$ 54.5	$ 3.3
Accounts payable – related parties		
EPO and affiliates	$ 5.5	$ 46.1
EPCO and affiliates	8.1	2.4
Total	$ 13.6	$ 48.5

(1) EPO borrowed $45.6 million under a Master Intercompany Loan Agreement. See "Significant Relationships and Agreements with EPO" under 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.

Significant Relationships and Agreements with EPO

Our assets connect to various midstream energy assets of EPO and form integral links within EPO's value chain. 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 to promote their operational efficiency and maximize value. In addition, we believe our relationship with EPO and EPCO provides us with a distinct benefit in both the operation of our assets and in the identification and execution of potential future acquisitions that are not otherwise taken by Enterprise Products Partners or Enterprise GP Holdings in accordance with our business opportunity agreements. One of our primary business purposes is to support the growth objectives of EPO and other affiliates under common control.

At December 31, 2009, EPO beneficially owned approximately 58.6% of our limited partner interests and 100% of our general partner. EPO was sponsor of the DEP I and DEP II drop down transactions and owns varying interests (as Parent) in the DEP I and DEP II Midstream Businesses. For a description of the DEP I and DEP II drop down transactions (including consideration provided to EPO), see Note 1. 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; however, EPO has no obligations or commitment to make such contributions or sales to us.

EPO has continued involvement with all of our subsidiaries, including the following types of transactions: (i) it utilizes our storage services to support its Mont Belvieu fractionation and other businesses; (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 is owned by us.

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 borrowed $1.3 million and EPO borrowed $45.6 million 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. The interest rate applicable to these short-term borrowings was 0.73%. Amounts borrowed by us and the related interest eliminate in consolidation.

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

§ indemnification for certain environmental liabilities, tax liabilities and right-of-way defects with respect to the DEP I and DEP II Midstream Businesses EPO contributed to us in connection with the respective drop down transactions;

§ funding by EPO of 100% of 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 IPO;

§ funding by EPO of 100% of post-December 8, 2008 capital expenditures to complete the Sherman Extension natural gas pipeline;

- § a right of first refusal to EPO 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; and

- § a preemptive right with respect to equity securities issued by certain of our subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

We and EPO have also 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.

Our general partner's Audit, Conflicts and Governance ("ACG") Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

Neither EPO nor any of its affiliates are restricted under the Omnibus Agreement from competing against us. As provided for in the EPCO ASA, EPO and its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to acquire or construct such assets.

As noted previously, EPO indemnified us for certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets it contributed to us in connection with the DEP I and DEP II drop down transactions. These indemnifications terminated on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage and we are not entitled to indemnification until the aggregate amount of claims we incur exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. We made no claims to EPO during the years ended December 31, 2009 and 2008.

For information regarding the funding by EPO of 100% of certain post-February 5, 2007 capital expenditures of South Texas NGL and Mont Belvieu Caverns, see "Noncontrolling Interest – DEP I Midstream Businesses – Parent" under Note 13.

Mont Belvieu Caverns' LLC Agreement. The Caverns LLC Agreement states that if Duncan Energy Partners elects to not participate in certain 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 projects from EPO within 90 days of such projects being placed in service. In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100% of the depreciation related to 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 provide for the following:

- § the acquisition by us from EPO 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;

§ the payment of distributions in accordance with an overall “waterfall” approach that stipulates that to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to their partners or members, such cash will be distributed first to us and then to EPO in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98.0% to EPO and 2.0% to us. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%;

§ the funding of operating cash flow deficits in accordance with each owner’s respective partner or member interest;

§ the election by either owner to fund cash calls associated with expansion capital projects. Since December 8, 2008, we have elected to not participate in such cash calls and, as a result, EPO has funded 100% of the expansion project costs of the DEP II Midstream Businesses. If we later elect to participate in any expansion projects, then we will be required to make a capital contribution for our share of the project costs.

Any capital contributions to fund expansion projects made by either us or EPO will increase such partner’s Distribution Base (and hence future priority return amounts) under the company agreement of Enterprise Texas. As noted, we have declined participation in expansion project spending since December 8, 2008. As a result, EPO has funded 100% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $817.9 million at December 31, 2009. The DEP Distribution Base was unchanged at $730.0 million at December 31, 2009.

Common Unit Purchase Agreement – June 2009 Equity Offering. Pursuant to a common unit purchase agreement, we repurchased 8,000,000 of our common units beneficially owned by EPO in June 2009. We repurchased an additional 943,400 of our common units beneficially owned by EPO in July 2009. The repurchase of common units beneficially owned by EPO was reviewed and approved by each of the ACG Committees of EPGP and DEP GP. See Note 12 for additional information regarding our June 2009 equity offering.

Transactions with TEPPCO. Beginning in 2008, Mont Belvieu Caverns commenced providing NGL and petrochemical storage services to TEPPCO. For the period January 2007 through March 2008, we leased from TEPPCO an 11-mile pipeline that was part of our South Texas NGL System. We discontinued this lease during the first quarter of 2008 when we completed the construction of a parallel pipeline. All of our related party activities and balances with TEPPCO, prior to their merger with EPO, have been aggregated with related party activities and balances that we present for EPO.

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 the ASA. We, Enterprise Products Partners Enterprise GP Holdings 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 as may be necessary to provide such services.

§ 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 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 compensation of 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 of general 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,		
	2009	2008	2007
Operating costs and expenses	$ 85.8	$ 72.1	$ 63.7
General and administrative expenses	10.9	15.7	11.5
Total costs and expenses	$ 96.7	$ 87.8	$ 75.2

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 Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us, Enterprise Products Partners and Enterprise GP Holdings to EPCO of distributions of cash or securities, if any, made by EPCO Unit to their respective Class B limited partners. The ASA amendment also extended the term under which EPCO provides services to the partnership entities from December 2010 to December 2013 and made other updating and conforming changes.

Relationship with Evangeline

Acadian Gas sold $155.5 million, $362.9 million and $264.2 million of natural gas to Evangeline, under its natural gas purchase contract with Evangeline, during the years ended December 31, 2009, 2008 and 2007, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract averaged approximately 50 BBtus/d during the twelve months ended December 31, 2009, 2008 and 2007, respectively. For the years ended December 31, 2008 and 2007, Evangeline was our largest customer and accounted for 22.7% and 21.7%, respectively, of our consolidated revenues. For the year ended December 31, 2009, another related party was our largest customer.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity, L.P. (together with its consolidated subsidiaries, "Energy Transfer Equity") and its general partner in May 2007.

As a result of common control of Enterprise GP Holdings and us, Energy Transfer Equity became a related party to us. Our revenues from Energy Transfer Equity are attributable to natural gas transportation 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 earnings per unit is computed by dividing net income or loss attributable to Duncan Energy Partners allocated to limited partner interests 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,		
	2009	2008	2007
Net income attributable to Duncan Energy Partners L.P.	$ 91.1	$ 47.9	$ 3.6
Subtract: Income allocated to former owners of DEP I Midstream Businesses	--	--	(5.0)
Add (subtract): Loss (income) allocated to former owners of the DEP II Midstream Businesses	--	(19.6)	20.6
Net income allocated to Duncan Energy Partners	91.1	28.3	19.2
Multiplied by DEP GP ownership interest (weighted-average for period)	0.7%	1.7%	2.0%
Net income allocation to DEP GP	$ 0.6	$ 0.5	$ 0.4

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. On December 8, 2008, DEP GP elected to forego making a cash contribution to us to maintain its 2.0% general partner interest in connection with the DEP II drop down transaction. 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 period indicated:

	For the Year Ended December 31,		
	2009	2008	2007
Net income allocation to Duncan Energy Partners	$ 91.1	$ 28.3	$ 19.2
Less: Income allocation to DEP GP	0.6	0.5	0.4
Net income allocation to limited partners	$ 90.5	$ 27.8	$ 18.8
Basic and diluted earnings per unit:			
Numerator (net income allocation to limited partners)	$ 90.5	$ 27.8	18.8
Denominator (weighted-average units outstanding):			
Common units	54.5	20.3	20.3
Class B units	3.2	2.5	--
Total units	57.7	22.8	20.3
Earnings per unit	$ 1.57	$ 1.22	$ 0.93

Note 17. Commitments and Contingencies

Litigation

On occasion, we are named as a defendant in litigation relating to our normal business operations, including regulatory and environmental matters. Although we insure against various business 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 as a result of our ordinary business activity. 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.

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, 2009, NGL and petrochemical products aggregating 20.9 million barrels were due to be redelivered to their owners along with 5,015 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Regulatory Matters

Certain recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide and methane, may be contributing to climate change. On June 26, 2009, the U.S. House of Representatives passed the “American Clean Energy and Security Act of 2009,” or “ACESA,” which would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases in the United States and would require most sources of greenhouse gas emissions to obtain greenhouse gas emission “allowances” corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun work on its own legislation for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency (“EPA”) announced its finding that emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Although it may take the EPA several years to adopt and impose regulations limiting emissions of greenhouse gases, any such regulation could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases would likely require us to incur increased operating costs, and may have an adverse effect on our business, financial position, demand for our operations, results of operations and cash flows.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2009. A description of each type of contractual obligation follows (dollars in millions):

	Payment or Settlement due by Period						
Contractual Obligations (1)	**Total**	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**
Scheduled maturities of long term debt (2)	$ 457.3	$ --	$ 457.3	$ --	$ --	$ --	$ --
Estimated cash interest payments (3)	$ 14.8	$ 11.1	$ 3.7	$ --	$ --	$ --	$ --
Operating lease obligations	$ 115.6	$ 9.0	$ 8.9	$ 8.7	$ 7.4	$ 6.6	$ 75.0
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 511.7	$ 257.3	$ 127.0	$ 127.4	$ --	$ --	$ --
Other	$ 0.1	$ *	$ *	$ *	$ --	$ --	$ --
Underlying major volume commitments:							
Natural gas (in BBtus)	77,207	40,657	18,250	18,300	--	--	--
Capital expenditure commitments (4)	$ 175.3	$ 175.3	$ --	$ --	$ --	$ --	$ --

* Indicates amounts are immaterial and less than $0.1 million.

(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) See Note 11 for additional information regarding our credit facilities.
(3) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at December 31, 2009. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2009. See Note 11 for information regarding variable interest rates charged in 2009 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements in place at December 31, 2009. See Note 6 for information regarding our derivative instruments.
(4) Capital expenditure commitments are reflected on a 100% basis before contributions from noncontrolling interest in connection with the Omnibus Agreement and Caverns LLC Agreement (see Note 15).

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 involve (i) the lease of underground caverns for the storage of natural gas and NGLs, primarily our lease for the Wilson natural gas storage facility and (ii) land held pursuant to right-of-way agreements.

We lease the Wilson natural gas storage facility, which is integral to the operations of our Texas Intrastate System. 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.

In addition, our 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, 2009, 2008 or 2007. Lease expense included in costs and expenses was $9.8 million, $10.8 million and $9.9 million for the twelve months ended December 31, 2009, 2008 and 2007, respectively.

Purchase Obligations. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (unconditional) on us that specify 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 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 at December 31, 2009 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2009, we do not have any other product purchase commitments with fixed or minimum pricing provisions having remaining terms in excess of one year.

We also have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services to be rendered or products to be delivered in connection with our capital spending programs. The contractual obligations table shows these capital project commitments for the periods indicated.

At December 31, 2009, we had approximately $175.3 million of consolidated capital expenditure commitments outstanding. These commitments primarily relate to announced expansions of the Acadian Gas System (i.e., the Haynesville Extension) and the Texas Intrastate System (i.e., the Sherman Extension and Trinity River Lateral). Currently, we have not elected to participate in these expansion projects; therefore, EPO will fund 100% of such costs. We may elect to participate in such projects in the future. For information regarding our relationship with EPO and related project funding arrangements, see Note 15.

Commitments under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 15). See Note 5 for additional information regarding accounting for equity awards.

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: (i) NGL transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas. As such, our results of operations, cash flows and financial position may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these products. In general, energy commodity product prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of hydrocarbon products transported, gathered, stored or fractionated at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, for reasons such as depressed commodity prices or a decrease in exploration and development activities, could result in a decline in the volume of natural gas and NGLs handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of: (i) general economic conditions; (ii) reduced demand by consumers for the end products made using NGLs; (iii) increased competition from petroleum-based products due to pricing differences; (iv) adverse weather conditions; (v) government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline; or (vi) other reasons, could adversely affect our results of operations, cash flows and financial position.

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.

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 are customary and sufficient 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 consolidated 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 to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated 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 $25.0 million per storm. EPCO's onshore program currently provides $150.0 million per occurrence for named windstorm events. For non-windstorm events, EPCO's deductible for onshore physical damage is $5.0 million per occurrence. With respect to business interruption insurance, onshore assets must be out-of-service in excess of 60 days before any losses from business interruptions will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first $50.0 million of any loss in excess of deductible amounts for our onshore assets. Any amounts expensed by the DEP I and DEP II Midstream Businesses will be included in net income and EPO's share of these losses will be attributed to noncontrolling interest.

In the third quarter of 2008, certain of our facilities located along the Gulf Coast of Texas and Louisiana were damaged by Hurricanes Gustav and Ike. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined cumulative total of $2.0 million of repair costs for property damage in connection with these two storms through December 31, 2009.

Interest Rate Risk

Our Revolving Credit Facility and Term Loan Agreement are variable rate debt obligations, which both expire in 2011. We have outstanding $175 million of variable-to-fixed interest rate swaps, all of which expire in September 2010, that partially hedge our exposure to changes in variable interest rates.

We cannot predict the costs of refinancing, at maturity, our existing credit facilities or the costs of new credit arrangements. A tight credit market, similar to the markets in late 2008 and early 2009, may have an adverse affect on our future ability to refinance our credit facilities at favorable rates or to enter into additional new credit arrangements. In addition, tight credit market conditions may translate into our having to agree to increasingly restrictive lender covenants. The inability to refinance or enter into new credit arrangements with favorable terms could impede our ability to fund capital requirements or to make distributions on our common units.

Note 19. Supplemental Cash Flow Information

The following table provides information regarding: (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for income taxes for the periods indicated.

	For the Year Ended December 31,		
	2009	2008	2007
Decrease (increase) in:			
Accounts receivable - trade	$ 39.6	$ 5.0	$ 9.7
Accounts receivable - related party	(55.5)	1.2	(4.2)
Gas imbalance receivables	25.9	(1.4)	28.7
Inventories	17.5	(6.0)	(6.8)
Prepaid and other current assets	(5.3)	1.6	(1.5)
Increase (decrease) in:			
Accounts payable - trade	(1.7)	(5.9)	15.8
Accounts payable - related party	(39.9)	13.5	31.0
Accrued costs and expenses	(42.7)	(10.1)	(47.7)
Accrued property taxes	0.8	1.6	1.7
Accrued taxes - other	0.1	4.8	2.7
Other current liabilities	(19.1)	6.5	(16.0)
Other long-term liabilities	(0.2)	(12.6)	0.8
Net effect of changes in operating accounts	$ (80.5)	$ (1.8)	$ 14.2
Cash payments for interest, net of $0.3, $0.3 and $2.6 capitalized in 2009, 2008 and 2007, respectively	$ 13.8	$ 11.5	$ 11.5
Cash payments for income taxes	$ 1.0	$ 0.2	$ --

We incurred liabilities for construction in progress that had not been paid at December 31, 2009, 2008 and 2007 of $41.8 million, $30.5 million and $24.8 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Statements of Consolidated Cash Flows.

The following table presents the components of depreciation, amortization and accretion for the periods indicated:

	For the Year Ended December 31,		
	2009	2008	2007
Depreciation, amortization and accretion expense:			
DEP I Midstream Businesses	$ 38.7	$ 34.3	$ 28.9
DEP II Midstream Businesses	147.4	133.1	146.6
Duncan Energy Partners L.P. standalone	2.2	0.4	0.1
Total	$ 188.3	$ 167.8	$ 175.6

Cash payments for significant business combinations were $35.0 million for the year ended December 31, 2007. In December 2007, we acquired the South Monco natural gas pipeline business ("South Monco") from a third party for $35.0 million in cash. South Monco primarily consists of 128 miles of pipelines located in southeast Texas that gather natural gas at the wellhead for regional producers for redelivery to various points, including our Texas Intrastate System. The South Monco system includes an amine treating unit and related dehydration facilities. The South Monco transaction was accounted for using the purchase method of accounting and, accordingly, such cost has been allocated to assets acquired and liabilities assumed based on estimated fair values.

Note 20. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2009 and 2008:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
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.:				
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
For the Year Ended December 31, 2008:				
Revenues	363.6	478.8	432.2	323.5
Operating income	21.1	15.8	18.7	12.3
Net loss (income) attributable to noncontrolling interest	(5.6)	0.6	(4.4)	2.0
Net income attributable to Duncan Energy Partners L.P.	13.3	13.3	10.6	10.7
Allocation of net income attributable to Duncan Energy Partners L.P.:				
Duncan Energy Partners L.P.				
Limited partners	5.9	6.5	3.7	11.7
General partner	0.1	0.1	0.1	0.2
Former owner of DEP II Midstream Businesses	7.3	6.7	6.8	(1.2)
Earnings per unit (basic and diluted)	0.29	0.32	0.18	0.39

Exhibit 12.1

DUNCAN ENERGY PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	For the Years Ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Consolidated net income	$ 45.8	$ 55.3	$ 23.6	$ 51.7	$ 30.1
Add: Provision for income taxes	1.3	1.1	4.2	1.7	--
Less: Equity in income of Evangeline	(1.1)	(0.9)	(0.2)	(1.0)	(0.3)
Consolidated pre-tax income before equity earnings from Evangeline	46.0	55.5	27.6	52.4	29.8
Add: Fixed charges	17.6	15.3	14.5	3.2	3.1
Amortization of capitalized interest	4.0	1.0	0.6	--	--
Subtotal	67.6	71.8	42.7	55.6	32.9
Less: Interest capitalized	(0.3)	(0.3)	(2.6)	--	--
Net loss (income) attributable to noncontrolling interest:					
DEP I Midstream Businesses - Parent	(15.3)	(11.4)	(20.0)	--	--
DEP II Midstream Businesses - Parent	60.6	4.0	--	--	--
Total earnings	$ 112.6	$ 64.1	$ 20.1	$ 55.6	$ 32.9
Fixed charges:					
Interest expense	$ 14.0	$ 11.4	$ 8.6	$ --	$ --
Capitalized interest	0.3	0.3	2.6	--	--
Interest portion of rental expense	3.3	3.6	3.3	3.2	3.1
Total	$ 17.6	$ 15.3	$ 14.5	$ 3.2	$ 3.1
Ratio of earnings to fixed assets	6.4x	4.2x	1.4x	17.4x	10.6x

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 before 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
- § 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 interest within rental expenses; and preference dividend requirements of consolidated subsidiaries.

Our ratio is significantly higher for the years ended December 31, 2006 and 2005 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, 2010

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	66%
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, 2010, 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, 2009.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010

EXHIBIT 31.1

CERTIFICATIONS

I, Richard H. Bachmann, 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, 2010

/s/ Richard H. Bachmann
Name: Richard H. Bachmann
Title: Chief Executive Officer of DEP Holdings, LLC,
the General Partner of Duncan Energy Partners L.P.

EXHIBIT 31.2

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, 2010

/s/ W. Randall Fowler
Name: W. Randall Fowler
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 RICHARD H. BACHMANN, 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, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Richard H. Bachmann, 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/ Richard H. Bachmann
Name: Richard H. Bachmann
Title: Chief Executive Officer of DEP Holdings, LLC,
the General Partner of Duncan Energy Partners L.P.

Date: March 1, 2010

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, 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, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, 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/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of DEP Holdings, LLC,
the General Partner of Duncan Energy Partners L.P.

Date: March 1, 2010