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, 2013

or

☐ **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 1-36175

MIDCOAST ENERGY PARTNERS, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**61-1714064**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

1100 Louisiana Street,
Suite 3300,
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code (713) 821-2000

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

Title of each class	Name of each exchange on which registered
Class A common units	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ 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 ☐ 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 ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☒

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of the 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. ☐

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

Large Accelerated Filer ☐	Accelerated Filer ☐
Non-Accelerated Filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of June 30, 2013, the last business day of the registrant's most recently completed second fiscal quarter, the registrant's equity was not listed on any domestic exchange or over-the-counter market.

As of February 14, 2014, the registrant has 22,610,056 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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Unless the context otherwise requires, references in this report to "the Predecessor," "we," "our," "us," or like terms, when used in a historical context (periods prior to November 13, 2013), refer to Midcoast Operating, L.P. and its subsidiaries. References in this report to "Midcoast Energy Partners," "the Partnership," "we," "our," "us," or like terms used in the present tense or prospectively (starting November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries. We refer to our general partner, Midcoast Holdings, L.L.C., as our "General Partner" and refer to Enbridge Energy Partners, L.P. and its subsidiaries, other than us, as "Enbridge Energy Partners," or "EEP." References to "Enbridge" refer collectively to Enbridge Inc. and its subsidiaries other than us, our subsidiaries, our General Partner and EEP, its subsidiaries and its general partner. References to "Midcoast Operating" refer to Midcoast Operating, L.P. and its subsidiaries. After the closing of our initial public offering on November 13, 2013, we own a 39% controlling interest in Midcoast Operating, and EEP owns a 61% non-controlling interest in Midcoast Operating. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP's 61% non-controlling interest in Midcoast Operating.

This Annual Report on Form 10-K includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Any forward-looking statement made by us in this Annual Report on Form 10-K speaks only as of the date on which it is made, and we undertake no obligation to publicly *update any forward-looking statement. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) changes in the demand for or the supply of, forecast data for, and price trends related to natural gas, natural gas liquids, or NGLs, and crude oil; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline and gathering systems, as well as other processing and treating plants; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to whom we sell products; (5) hazards and operating risks that may not be covered fully by insurance; (6) changes in or challenges to our rates; and (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance.*

For additional factors that may affect results, see "Item 1A. Risk Factors" included elsewhere in this Annual Report on Form 10-K and our subsequently filed Quarterly Reports on Form 10-Q, which are available to the public over the Internet at the U.S. Securities and Exchange Commission's, or the SEC's, website (www.sec.gov) and at our website (www.midcoastpartners.com).

Glossary

The following abbreviations, acronyms and terms used in this Form 10-K are defined below:

Anadarko system	Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle which serve the Anadarko basin, inclusive of the Elk City system
AOCI	Accumulated other comprehensive income
Bbl	Barrel of liquids (approximately 42 United States gallons)
Bpd	Barrels per day
CAA	Clean Air Act
CAD	Amount denominated in Canadian dollars
CWA	Clean Water Act
East Texas system	Natural gas gathering, treating and processing assets in East Texas that serve the Bossier trend and Haynesville shale areas. Also includes a system formerly known as the Northeast Texas system
EBITDA	Earnings before Interest, Taxes, Depreciation and Amortization
EEP	Enbridge Energy Partners, L.P. and its subsidiaries other than Midcoast Energy Partners, L.P. and its subsidiaries
Elk City system	Elk City natural gas gathering and processing system located in western Oklahoma in the Anadarko basin
Enbridge	Enbridge Inc., of Calgary, Alberta, Canada, the ultimate parent of the General Partner
Enbridge Management	Enbridge Energy Management, L.L.C.
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
General Partner	Midcoast Holdings, L.L.C., the general partner of the Partnership
ISDA®	International Swaps and Derivatives Association, Inc.
LIBOR	London Interbank Offered Rate—British Bankers' Association's average settlement rate for deposits in United States dollars
MEP	Midcoast Energy Partners, L.P. and its consolidated subsidiaries
MMBtu/d	Million British Thermal units per day
MMcf/d	Million cubic feet per day
NGA	Natural Gas Act
NGL or NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act
North Texas system	Natural gas gathering and processing assets located in the Fort Worth basin serving the Barnett Shale area
NPNS	Normal purchases and normal sales
NYMEX	The New York Mercantile Exchange where natural gas futures, options contracts and other energy futures are traded
NYSE	New York Stock Exchange
Partnership Agreement	First Amended and Restated Agreement of Limited Partnership of Midcoast Energy Partners, L.P.
Partnership	Midcoast Energy Partners, L.P. and its consolidated subsidiaries
SEC	United States Securities and Exchange Commission
TSX	Toronto Stock Exchange
U.S. GAAP	United States Generally Accepted Accounting Principles

PART I

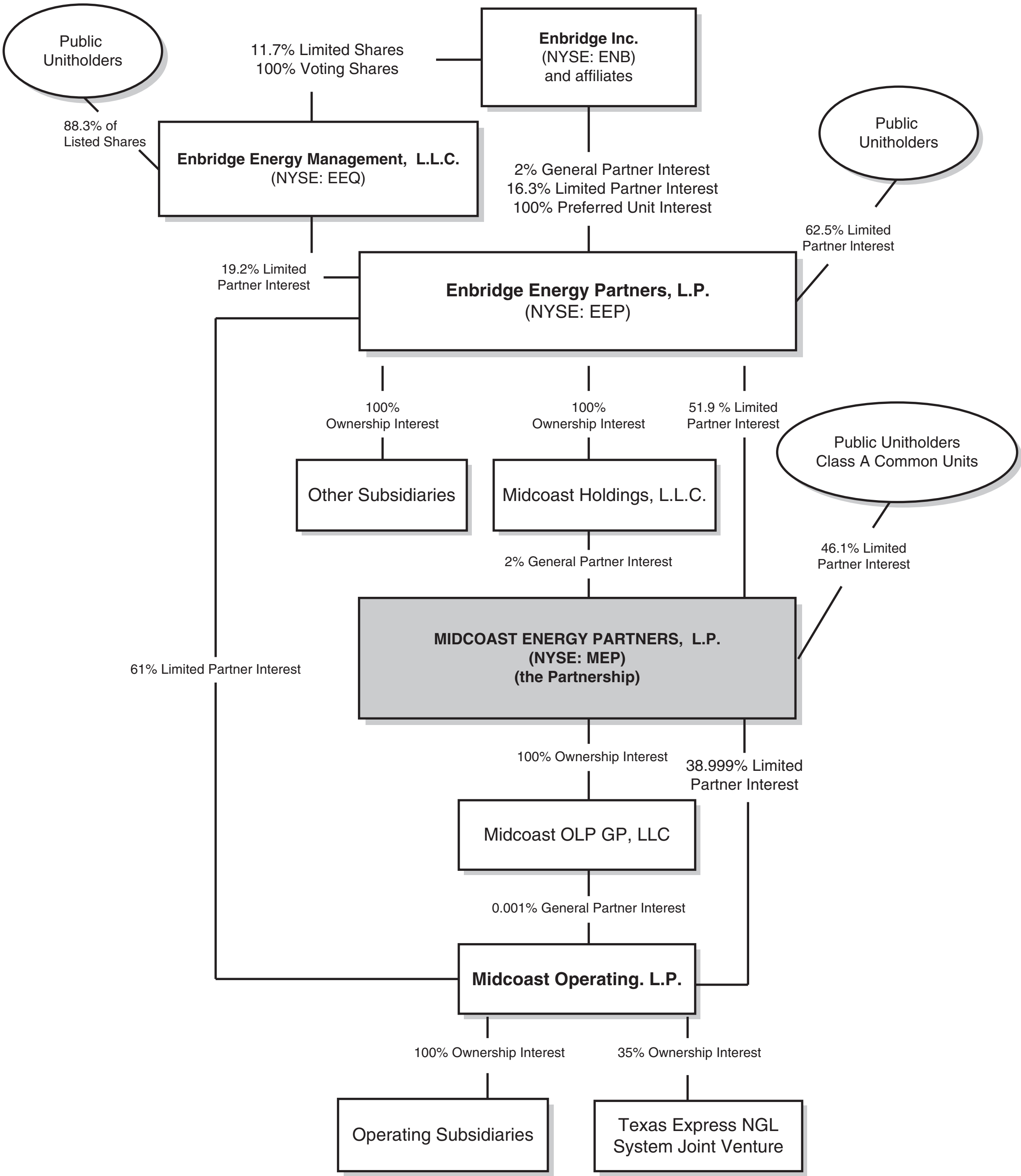
Item 1. Business

OVERVIEW

In this report, unless the context otherwise requires, references to “the Predecessor,” “we,” “our,” “us,” or like terms, when used in a historical context (periods prior to November 13, 2013), refer to Midcoast Operating, L.P. and its subsidiaries. References in this report to “Midcoast Energy Partners,” “MEP,” “the Partnership,” “we,” “our,” “us,” or like terms used in the present tense or prospectively (starting November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries. We refer to our general partner, Midcoast Holdings, L.L.C., as our “General Partner” and refer to Enbridge Energy Partners, L.P. and its subsidiaries, other than us, as “Enbridge Energy Partners,” or “EEP.” References to “Enbridge” refer collectively to Enbridge Inc. and its subsidiaries other than us, our subsidiaries, our General Partner and EEP, its subsidiaries and its general partner. References to “Midcoast Operating” refer to Midcoast Operating, L.P. and its subsidiaries. After the closing of our initial public offering on November 13, 2013, we own a 39% controlling interest in Midcoast Operating, and EEP owns a 61% non-controlling interest in Midcoast Operating. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP’s 61% non-controlling interest in Midcoast Operating.

We are a publicly traded growth-oriented Delaware limited partnership formed in 2013 by Enbridge Energy Partners, L.P., or EEP, to serve as EEP’s primary vehicle for owning and growing its natural gas and natural gas liquids, or NGL, midstream business in the United States. As a pure-play United States natural gas and NGL midstream business, we will be able to pursue a focused and flexible strategy, will have direct access to the equity and debt capital markets, and will have the opportunity to grow through organic growth opportunities and acquisitions, including drop-down transactions from EEP. We completed our initial public offering, or the Offering, of our Class A common units on November 13, 2013. Our Class A common units are traded on the New York Stock Exchange, or NYSE, under the symbol MEP.

The following chart shows our organization and ownership structure as of December 31, 2013. The ownership percentages referred to below illustrate the relationships among us, Midcoast Operating, our General Partner, EEP, Enbridge and its affiliates:



As part of the transactions in connection with the Offering, we acquired 100% of the limited liability company interests of Midcoast OLP GP, L.L.C. and a 39% controlling interest in Midcoast Operating, a Texas limited partnership that owns a network of natural gas and NGL gathering and transportation systems, natural gas processing and treating facilities and NGL fractionation facilities primarily located in Texas and Oklahoma. Midcoast Operating also owns and operates natural gas, condensate and NGL logistics and marketing assets that primarily support its gathering, processing and transportation business. Through our ownership of Midcoast Operating's general partner, we control, manage and operate these systems. EEP has retained a 61% non-controlling interest in Midcoast Operating.

Our business primarily consists of gathering unprocessed and untreated natural gas from wellhead locations and other receipt points on our systems, processing the natural gas to remove NGLs and impurities at our processing and treating facilities and transporting the processed natural gas and NGLs to intrastate and interstate pipelines for transportation to various customers and market outlets. In addition, we also market natural gas and NGLs to wholesale customers.

We seek to provide our customers with best-in-class field-level service and responsiveness using our significant platform of natural gas and NGL infrastructure. We are able to provide our customers with integrated wellhead-to-market service from our systems to major energy market hubs in the Gulf Coast and Mid-Continent regions of the United States. From these market hubs, natural gas and NGLs are either consumed in local markets or transported to consumers in the midwest, northeast and southeast United States.

Midcoast Operating's primary operating assets include:

- Approximately 11,600 miles of natural gas gathering and transportation lines and approximately 226 miles of NGL gathering and transportation lines;
- A 35% interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together own a 580-mile, 20-inch NGL intrastate transportation pipeline extending from the Texas Panhandle to Mont Belvieu, Texas and a related NGL gathering system that consists of approximately 116 miles of gathering lines;
- 21 active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, with a combined capacity of approximately 2.0 billion cubic feet per day, or Bcf/d, including 350 million cubic feet per day, or MMcf/d, provided by our HCDP plants;
- Eight active natural gas treating plants, including three that are leased from third parties, with a total combined capacity of approximately 1.1 Bcf/d;
- Approximately 570 compressors with approximately 816,000 aggregate horsepower, the substantial majority of which are owned by Midcoast Operating and the remainder of which are leased from third parties;
- A liquids railcar loading facility near Pampa, Texas, which we refer to as our TexPan liquids railcar facility;
- An approximately 40-mile crude oil pipeline and associated crude oil storage facility near Mayersville, Mississippi, including a crude oil barge loading facility located on the Mississippi River; and
- Approximately 250 transport trucks, 300 trailers and 205 railcars for transporting NGLs.

BUSINESS STRATEGY

Our principal financial objective is to increase the amount of cash distributions we make to our unitholders over time while maintaining our focus on safety and stability in our business. Our plan for executing this objective includes the following key business strategies:

1. ***Maintain safe and reliable operations***
    - We are committed to maintaining and continually improving the safety, reliability and efficiency of our operations, which we believe is key to attracting new customers and maintaining

relationships with our current customers, regulators and the communities in which we operate. We strive for operational excellence by utilizing robust programs to integrate environmental integrity, health and occupational safety and risk management principles throughout our business. We employ comprehensive integrity management, inspection, monitoring and audit initiatives in support of this strategy.

2. ***Pursuing accretive acquisitions from EEP and third parties***

- We intend to pursue acquisitions of additional interests in Midcoast Operating from EEP, as well as accretive acquisitions of complementary assets from third parties. EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time, although EEP is not legally obligated to do so. We do not know when or if any such additional interests will be offered to us to purchase. In addition, in conjunction with EEP, we monitor the marketplace to identify and pursue acquisitions from third parties that complement or diversify our existing operations.

3. ***Pursuing economically attractive organic growth opportunities***

- We seek out attractive organic expansion and asset enhancement opportunities that leverage our existing asset footprint, strategic relationships with our customers and our management team's expertise in constructing, developing and optimizing midstream infrastructure assets. The organic development projects we pursue are designed to extend our geographic reach, diversify our customer base, expand our gathering systems and our processing and treating capacity, enhance end-market access and/or maximize throughput volumes. For more information relating to growth opportunities refer to Item 1. *Business Segments.*

4. ***Enhancing the profitability of our existing assets***

- To address the increasing producer focus on the liquids portion of the midstream natural gas value chain, we expect to continue to increase our natural gas processing capacity, NGL takeaway capacity options, and our third party fractionation alternatives, which we believe will, over the long-term, increase the attractiveness and profitability of our natural gas and NGL systems, attract new customers and increase our business with existing customers. We seek to capitalize on opportunities to attract new customers, increase volumes of natural gas and NGLs that we gather, transport, process or treat and otherwise enhance utilization and operating efficiencies, including increasing customer access to preferred natural gas and NGL markets. We believe our approach will provide our customers with greater value for their commodities and increase the utilization of our natural gas and NGL systems.

5. ***Maintaining a conservative and flexible capital structure and targeting investment grade credit metrics in order to lower our overall cost of capital.***

- We intend to maintain a balanced capital structure that should afford us access to the capital markets at a competitive cost of capital. Although we do not currently have a credit rating, we plan to target debt-to-EBITDA (earnings before interest, taxes, depreciation and amortization), EBITDA-to-interest and other key credit metrics that are consistent with investment grade businesses in our industry. We intend to finance long-term growth projects and acquisitions with a balanced combination of debt and equity that we believe will, together with our balanced capital structure, promote the long-term stability of our business.

BUSINESS SEGMENTS

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing.

These segments have unique business activities that require different operating strategies. For information relating to revenues from external customers, operating income and total assets for each segment, refer to Note 16. *Segment Information* of our consolidated financial statements included in Item 8. *Financial Statements and Supplementary Data* of this report.

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. We gather natural gas from the wellhead and central receipt points on our systems, deliver it to our facilities for processing and treating and deliver the residue gas to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies. We deliver the NGLs produced at our processing and fractionation facilities to intrastate and interstate pipelines for transportation to the NGL market hubs in Mont Belvieu, Texas and Conway, Kansas. In addition, during the fourth quarter of 2013, we began delivering NGLs from certain of our facilities to the Texas Express NGL system for transportation on the Texas Express NGL mainline to Mont Belvieu, Texas.

Our gathering, processing and transportation business consists of the following four systems:

- *Anadarko system:* Approximately 3,100 miles of natural gas gathering and transportation pipelines, approximately 58 miles of NGL pipelines, nine active natural gas processing plants, three standby natural gas processing plants and one standby treating plant located in the Anadarko basin.
- *East Texas system:* Approximately 3,900 miles of natural gas gathering and transportation pipelines, approximately 108 miles of NGL pipelines, six active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, eight active natural gas treating plants, three standby natural gas treating plants and one fractionation facility located in the East Texas basin.
- *North Texas system:* Approximately 4,600 miles of natural gas gathering and transportation pipelines, approximately 60 miles of NGL pipelines, six active natural gas processing plants and one standby natural gas processing plant located in the Fort Worth basin.
- *Texas Express NGL system:* A 35% interest in an approximately 580-mile NGL intrastate transportation mainline and a related NGL gathering system that consists of approximately 116 miles of gathering lines.

Customers. Our gathering, processing and transportation business serves customers predominantly in the Gulf Coast region of the United States and includes both upstream customers and purchasers of natural gas and NGLs. Upstream customers served by our systems primarily consist of small, medium and large independent operators and large integrated energy companies, while our demand market customers primarily consist of large users of natural gas, such as power plants, industrial facilities, local distribution companies and other large consumers. Due to the cost of making physical connections from the wellhead to gathering systems, the majority of our customers tend to renew their gathering and processing contracts with us rather than seeking alternative gathering and processing services.

Supply and Demand. Demand for our gathering, processing and transportation services primarily depends upon the supply of natural gas reserves and the drilling rate for new wells. The level of impurities in the natural gas gathered also affects treating services. Demand for these services depends upon overall economic conditions and the prices of natural gas and NGLs. During 2013, NGL prices were at levels higher than prices experienced in the prior year, while natural gas prices were only slightly higher than the prior year. Condensate pricing remained strong and is more closely associated with movements in domestic crude oil prices. As a result of the combination of these pricing dynamics, drilling activity has increased in areas known to have natural gas with high levels of NGL content, such as the Granite Wash play and the Barnett Shale. Additionally, supply in both of these areas has benefited from enhanced horizontal drilling and fracturing techniques, enabling higher flow rates from the wells of the producers. As drilling rates improve, and the number of drilling rigs increase, we would expect the demand for our services to increase. Our existing systems are located in basins that have the opportunity to grow in an improved pricing environment. All of our gathering, processing and transportation systems exist in regions that have shale or tight sands formations where horizontal fracturing technology can be utilized to increase production from the natural gas wells.

Anadarko System

Our Anadarko system includes production from the Granite Wash tight sand formation. Productive horizons in the Granite Wash play include the Hogshooter, Checkerboard, Cleveland, Skinner, Red Fork, Atoka and Morrow formations. Favorable pricing for NGLs relative to natural gas has encouraged producers to increase production in the Granite Wash play due to the high NGL and condensate content. The Anadarko basin wells generally have long lives with predictable flow rates. Producers are pursuing wells with higher condensate and oil production relative to historical activity that was focused on lower-valued gas prospects.

We expect development of the Granite Wash play in the Texas Panhandle and western Oklahoma to continue due to the prolific nature of the wells, current market prices for NGLs and crude oil and the application of horizontal drilling and fracturing technology to the formation. In order to accommodate the expected growth of the Granite Wash play, we began commissioning the operations of a cryogenic processing plant in the third quarter of 2013, which we refer to as our Ajax processing plant. The Ajax processing plant, condensate stabilizer, field and plant compression, gathering infrastructure and NGL pipelines assist in meeting the anticipated volume growth within our Anadarko system. The total cost of constructing the Ajax processing plant and related facilities was approximately $230 million. The Ajax processing plant increases the total processing capacity of our Anadarko system by approximately 150 million cubic feet per day, or MMcf/d, to approximately 1,150 MMcf/d and also increases the system's condensate stabilization capacity by approximately 2,000 Bpd. The Ajax processing plant is capable of producing approximately 15,000 barrels per day, or Bpd, of NGLs now that the Texas Express NGL pipeline, which we refer to as the mainline, is complete and was put into operation during the fourth quarter of 2013.

Our Anadarko system has numerous market outlets for the natural gas that we gather and process and NGLs and condensate that we recover on our system. We have connections to major intrastate and interstate transportation pipelines that connect our facilities to major market hubs in the Mid-Continent and Gulf Coast regions of the United States. All of our owned residue gas and condensate is sold to our logistics and marketing business. A portion of our owned NGLs is sold directly to OneOk Partners, L.P. ("ONEOK"), while the remainder is sold to our logistics and marketing business. The NGLs produced at our Anadarko system processing plants are transported by pipeline to third party fractionation facilities and NGL market hubs in Conway, Kansas and Mont Belvieu, Texas.

East Texas System

Our East Texas system gathers production from the Cotton Valley Lime and lean Bossier Shale plays, which are located on the western side of our East Texas system; the Haynesville/Bossier Shale plays, which run from western Louisiana into East Texas and are among the largest natural gas resources in the United States; and the Cotton Valley Sand formation, which also runs from western Louisiana into East Texas and has a high content of NGLs and condensate on the eastern side of our East Texas system. The East Texas basin also includes multiple other natural gas and oil formations that are frequently explored, including the Woodbine, Travis Peak, James Lime, Rodessa, and Pettite, among other formations. The East Texas wells generally have long lives with predictable flow rates. While dry gas drilling declined with the historical decreases in gas prices, more recently, drilling activity has increased in the basin by customers pursuing rich gas formations using horizontal drilling and multistage fracturing.

In the third quarter of 2013, we initiated construction activities at our Beckville processing plant and the related facilities on our East Texas system. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. We estimate the cost of constructing the plant to be approximately $145 million and expect it to commence service in early 2015.

Our East Texas system has numerous market outlets for the natural gas that we gather and process and NGLs and condensate that we recover on our system. We have connections to major intrastate and interstate transportation pipelines that connect our facilities to major market hubs in the United States Gulf Coast, as well as to several wholesale customers. The majority of our owned residue gas is sold to our logistics and marketing business, while the remainder of our owned residue gas is sold directly to third-party wholesale customers or utilities. All of our owned condensate is sold to our logistics and marketing business. A portion of the NGLs produced at one of our East Texas system processing plants is fractionated by us and sold directly to a third-party chemical company. The remainder of the NGLs recovered at our plants are sold to our logistics and marketing business and transported by pipeline to Mont Belvieu, Texas for fractionation.

North Texas System

A substantial portion of natural gas on our North Texas system is produced in the Barnett Shale play within the Fort Worth basin. The North Texas wells are located in the Fort Worth basin and generally have long lives with predictable flow rates. Producers are pursuing wells with higher condensate and oil production relative to historical activity due to the relatively lower valued gas prospects.

Our North Texas system has numerous market outlets for the natural gas that we gather and process and NGLs that we recover on our system. We have connections to major intrastate transportation pipelines that connect our facilities to market centers in the Dallas-Fort Worth area and ultimately to major market hubs in the United States Gulf Coast. The majority of our owned residue gas and all of our owned condensate and NGLs produced at our North Texas system processing plants is sold to our logistics and marketing business.

Texas Express NGL System

Volumes from the Rockies, Permian basin and Mid-Continent regions will be delivered to the Texas Express NGL system utilizing Enterprise Products Partners' existing Mid-America Pipeline between the Conway hub and Enterprise Products Partners' Hobbs NGL fractionation facility in West Texas. In addition, volumes from and to the Denver-Julesburg basin in Weld County, Colorado will be able to access the system upon the completion of the Front Range Pipeline by Enterprise Products Partners, DCP Midstream and Anadarko Petroleum Corporation, which could occur as early as the first quarter of 2014.

The Texas Express NGL system commenced startup operations during the fourth quarter of 2013. During startup operations, revenue recognition is delayed while the system is being filled with NGLs but operating costs are recognized. Additionally, the Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. These factors in combination contributed to lower equity earnings.

Competition. Competition for our gathering, processing and transportation business is significant in all of the markets we serve. Competitors include interstate and intrastate pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs. Our gathering business' principal competitors are other midstream companies and, to a lesser extent, producer owned gathering systems. Some of these competitors are substantially larger than we are. Competition for the services we provide varies based upon the location of gathering, treating and processing facilities. Most upstream customers have alternate gathering, treating and processing facilities available to them. In addition, they have alternatives such as building their own gathering facilities or, in some cases, selling their natural gas supplies without treating and processing. In addition to location, competition also varies based upon pricing arrangements and reputation. On sour natural gas systems, such as parts of our East Texas system, competition is more limited in certain locations due to the infrastructure required to treat sour natural gas. Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipeline companies. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers we serve have multiple pipelines connected or adjacent to their facilities. Accordingly, many of these customers have the ability to purchase natural gas directly from a number of pipelines or third parties that may hold capacity on the various pipelines. In addition, several new interstate natural gas pipelines have been and are being constructed in areas currently served by our natural gas transportation pipelines. Some of these new pipelines may compete for customers with our existing pipelines.

Logistics and Marketing

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business, thereby enhancing our competitive position. In addition, our logistics and marketing services provide our customers with the opportunity to receive enhanced economics by providing access to premium markets through the transportation capacity and other assets we control. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from pipeline systems and processing plants and sells and delivers them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants.

The physical assets of our logistics and marketing business primarily consist of:

- Approximately 250 transport trucks, 300 trailers and 205 railcars for transporting NGLs;
- Our TexPan liquids railcar facility near Pampa, Texas;
- An approximately 40-mile crude oil pipeline and associated crude oil storage facility near Mayersville, Mississippi, including a crude oil barge loading facility located on the Mississippi River; and
- An approximately 30-mile propylene pipeline extending from Exxon's refinery in Chalmette, Louisiana to an interconnecting Chevron pipeline near Lafitte, Louisiana.

We also enter into agreements with various third parties to obtain natural gas and NGL supply, transportation, gas balancing, fractionation and storage capacity in support of the logistics and marketing services we provide to our gathering, processing and transportation business and to third-party customers. These agreements provide our logistics and marketing business with the following:

- up to approximately 79,000 Bpd of firm NGL fractionation capacity;
- approximately 2.5 Bcf of firm natural gas storage capacity;
- up to approximately 120,000 Bpd of firm NGL transportation capacity on the Texas Express NGL system;
- up to approximately 89,000 Bpd of additional NGL transportation capacity, a significant portion of which is firm capacity, through transportation and exchange agreements with four NGL pipeline transportation companies; and
- approximately 5.0 MMBbls of firm NGL storage capacity.

Customers. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from our gathering, processing and transportation business as well as from third-party pipeline systems and processing plants and sells and delivers them to third-party customers. Most of the third-party customers of our logistics and marketing operations are wholesale customers, such as refiners and petrochemical producers, fractionators, propane distributors and industrial, utility and power plant customers. In addition, we sell natural gas and NGLs to marketing companies at various market hubs.

Supply and Demand. Supply for our logistics and marketing business depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our gathering, processing and transportation business. Demand is typically driven by weather-related factors with respect to power plant and utility customers and industrial demand.

Since major market hubs for natural gas and NGLs are located in the Mid-Continent and Gulf Coast regions of the United States and our logistics and marketing business assets are geographically located within Texas, Louisiana, Oklahoma, Kansas and Mississippi, the majority of activities conducted by our logistics and marketing business are conducted within those states. However, our logistics and marketing assets, including our firm transportation capacity and firm natural gas storage capacity, are able to provide us and third parties with access to markets outside of the Mid-Continent and Gulf Coast regions in order to respond to market demand and to realize enhanced value from favorable pricing differentials. Additionally, our firm transportation capacity and our fleet of trucks, trailers and railcars mitigates the risk that our natural gas and NGLs will be shut in by capacity constraints on downstream NGL pipelines and other facilities.

One of the key components of our logistics and marketing business is our natural gas and NGL purchase and resale business. Through our natural gas and NGL purchase and resale operations, we can efficiently manage the transportation and delivery of natural gas and NGLs from our gathering, processing and transportation assets and deliver them through major natural gas transportation pipelines to industrial, utility and power plant customers, as well as to marketing companies at various market hubs throughout the Mid-Continent, Gulf Coast and Southeast regions of the United States. We typically price our sales based on a published daily or monthly price index. In addition, sales to wholesale customers include a pass-through charge for costs of transportation and additional margin to compensate us for the associated services we provide.

Our logistics and marketing business also uses third-party storage facilities and pipelines for the right to store natural gas and NGLs for various periods of time under firm storage, interruptible storage or parking and lending services in order to mitigate risk associated with sales and purchase contracts. We also contract for third-party pipeline capacity under firm transportation contracts for which the pipeline capacity depends on volumes of natural gas from our natural gas assets. We contract this pipeline capacity for various lengths of time and at rates that allow us to diversify our customer base by expanding our service territory. We have also entered into multiple long-term fractionation contracts with third-party fractionators to provide access to fractionation capacity for our customers.

Competition. Our logistics and marketing business has numerous competitors, including large natural gas and NGL marketing companies, marketing affiliates of pipelines, major oil, natural gas and NGL producers, other trucking, railcar and pipeline operations, independent aggregators and regional marketing companies. Our logistics and marketing business' principal competitors include numerous natural gas and NGL marketing companies such as Energy Transfer Partners, Enterprise Products Partners, ONEOK, Targa Resources Partners and DCP Midstream, LLC and major integrated oil and natural gas companies.

Seasonality

Demand for our gathering, processing and transportation services primarily depends upon the supply of natural gas production and the drilling rate for new wells. The drilling activities of producers within our areas of operations generally do not vary materially by season but may be affected by adverse weather. Supply for our logistics and marketing operations depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our gathering, processing and transportation business. Generally, the demand for natural gas and NGLs decreases during the spring and fall months and increases during the winter months and, in some areas, during the summer months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. Demand for natural gas with respect to power plant and utility customers is typically driven by weather-related factors.

REGULATION

Regulation of Intrastate Natural Gas Pipelines

Our operations in Texas are subject to regulation under the Texas Utilities Code and the Texas Natural Resources Code, as implemented by the Texas Railroad Commission, or TRRC. Generally, the TRRC is vested with authority to ensure that rates charged for natural gas sales and transportation services are just and reasonable. The rates we charge for transportation services are deemed just and reasonable under Texas law, unless challenged in a complaint. We cannot predict whether such a complaint may be filed against us or whether the TRRC will change its method of regulating rates. The Texas Natural Resources Code provides that an Informal Complaint Process that is conducted by the Texas Railroad Commission shall apply to any rate issues associated with gathering or transmission systems, thus subjecting the gathering and/or intrastate pipeline activities of Enbridge to the jurisdiction of the Texas Railroad Commission via its Informal Complaint Process.

In Oklahoma, intrastate natural gas pipelines and gathering systems are subject to regulation by the Oklahoma Corporation Commission (OCC). Specifically, the OCC is vested with the authority to prescribe and enforce rates for the transportation and transmission of natural gas. These rates may be amended or altered at any time by the OCC. However, a company affected by a rate change will be given at least ten days' notice in order to introduce evidence of opposition to such amendment. Adjustment of claims or settlement of controversies regarding rates between transportation/transmission companies and employees or patrons will be mediated by the OCC. A corporation is subject to the OCC for failure to comply with rate requirements, resulting in contempt proceedings instituted by any affected party.

Regulation by the FERC of Intrastate Natural Gas Pipelines

Our Texas and Oklahoma intrastate pipelines are generally not subject to regulation by the FERC. However, to the extent our intrastate pipelines transport natural gas in interstate commerce, the rates, terms and conditions of such transportation are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. At least one of our intrastate pipelines will file for FERC approval of new rates in 2014. In addition, under FERC regulations we are subject to market manipulation and transparency rules. This includes the annual reporting requirements pursuant to FERC Order No. 735 *et al*. Failure to comply with FERC's rules, regulations and orders can result in the imposition of administrative, civil and criminal penalties.

Natural Gas Gathering Regulation

Section 1(b) of the Natural Gas Act, or NGA, exempts natural gas gathering facilities from the jurisdiction of the FERC. We own certain natural gas facilities that we believe meet the traditional tests the FERC has used to establish a facility's status as a gatherer not subject to FERC jurisdiction. However, to the extent our gathering systems buy and sell natural gas, such gatherers, in their capacity as buyers and sellers of natural gas, are now subject to FERC Order 704 and subsequent reissuances of the Order (currently Order 704-C). State regulations of gathering facilities typically address the safety and environmental concerns involved in the design, construction, installation, testing and operation of gathering facilities. In addition, in some circumstances, nondiscriminatory requirements are also addressed; however, historically rates have not fallen under the purview of state regulations for gathering facilities. Many of the producing states have previously adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access or perceived rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to significant and unduly burdensome state or federal regulation of rates and services.

NGL Pipeline Regulation

The mainline and gathering portions of Texas Express are common carriers subject to the regulation by various federal agencies and/or the TRRC. The FERC regulates the interstate pipeline transportation of crude oil, petroleum products, and other liquids such as NGL's, collectively called "petroleum pipelines." FERC regulates these operations pursuant to the Interstate Commerce Act (ICA) and the Energy Policy Act of 1992 or EPAct of 1992. The ICA and its implementing regulations require that tariff rates for interstate service on petroleum pipelines be just and reasonable and must not be unduly discriminatory or confer undue preference on any shipper.

EPAct 1992 required the FERC to establish a simplified and generally applicable ratemaking methodology for interstate petroleum pipelines. As a result, the FERC adopted an indexed rate methodology. If the rate level on Texas Express Pipeline were subject to formal review or challenge before the FERC, Texas Express would be required to produce a traditional cost of service review justifying its revenues.

Two of our other NGL lines, which do not provide service to third parties, operate under FERC granted waivers from the reporting requirements of Sections 6 and 20 of the ICA. These waivers are effective until a third party shipper requests service. In addition, certain of our NGL lines are subject to regulation as a common carrier by the TRRC. The TRRC's jurisdiction extends to both rates and pipeline safety. The rates we charge for NGL transportation service are deemed just and reasonable under Texas law unless challenged by a complaint. Complaints to state agencies have been infrequent and are usually informally resolved. Although we cannot assure you that our intrastate rates would ultimately be upheld if challenged, we believe that, given this history, the tariffs now in effect are not likely to be challenged or, if challenged, are not likely to be ordered to be reduced.

Safety Regulation and Environmental

General

Our transmission and gathering pipelines, storage and processing facilities, trucking and railcar operations are subject to extensive federal and state environmental, operational and safety regulation. The added costs imposed by regulations are generally no different than those imposed on our competitors. The failure to comply with such rules and regulations can result in substantial penalties and/or enforcement actions and added operational costs.

Pipeline Safety and Transportation Regulation

Some of our gas pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Pipeline Safety Improvement Act of 2002, or PSIA, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or the PIPES Act. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas, or HCAs. Our NGL pipelines, our crude oil pipeline and our propylene pipeline are subject to regulation by PHMSA under the Hazardous Liquid Pipeline Safety Act of 1979, or the HLPSA, which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline, and the Pipeline Safety Act of 1992, or the PSA, which added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the Accountable Pipeline Safety and Partnership Act of 1996, or the APSA, which limited the operator identification requirement to operators of pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management.

PHMSA has developed regulations that require pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

Although many of our pipeline facilities are not classified as transmission pipelines and currently are not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with our transmission pipelines on an annual basis as required by existing DOT regulations and their state counterparts. This estimate does not include the costs for any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. If future DOT pipeline integrity management regulations were to require that we expand our integrity management program to currently unregulated pipelines, including gathering lines, costs associated with compliance may have a material effect on our operations.

Recently enacted pipeline safety legislation, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the 2011 Pipeline Safety Act, reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. On August 13, 2012, PHMSA published a proposed rulemaking consistent with the signed act that, once finalized, will increase the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after January 3, 2012 to $200,000 per violation per day, with a maximum of $2,000,000 for a related series of violations. The PHMSA recently issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. The PHMSA has also published advanced notice of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. PHMSA also recently published an advisory bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. We have performed hydrotests of our facilities to confirm the maximum allowable operating pressure and do not expect that any final rulemaking by PHMSA regarding verification of maximum allowable operating pressure would materially affect our operations or revenue.

The National Transportation Safety Board has recommended that the PHMSA make a number of changes to its rules, including removing an exemption from most safety inspections for natural gas pipelines installed before

1970. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly by extending through more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We have incorporated all existing requirements into our programs by the required regulatory deadlines, and are continually incorporating the new requirements into procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and upcoming changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity transported by our system, or a regulatory inspection identifies a deficiency in our required programs.

When hydrocarbons are released into the environment or violations identified during an inspection, PHMSA may issue a civil penalty or enforcement action, which can require internal inspections, pipeline pressure reductions and other methods to manage or verify the integrity of a pipeline in the affected area. In addition, the National Transportation Safety Board may perform an investigation of a significant accident to determine the probable cause and issue safety recommendations to prevent future accidents.

We believe that our pipeline, trucking and railcar operations are in substantial compliance with applicable operational and safety requirements. In instances of non-compliance, we have taken actions to remediate the situations. Nevertheless, significant operating expenses and capital expenditure could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of our current pipeline control system or other safety equipment.

Environmental Regulation

General. Our operations are subject to complex federal, state and local laws and regulations relating to the protection of health and the environment, including laws and regulations that govern the handling, storage and release of crude oil and other liquid hydrocarbon materials or emissions from natural gas compression facilities. As with the pipeline and processing industry in general, complying with current and anticipated environmental laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position since the operations of our competitors are generally similarly affected.

In addition to compliance costs, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, injunctions banning or delaying certain activities. We believe that our operations are in substantial compliance with applicable environmental laws and regulations.

There are also risks of accidental releases into the environment associated with our operations, such as releases or spills of crude oil, liquids, natural gas or other substances from our pipelines or storage facilities.

Such accidental releases could, to the extent not insured, subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines, penalties or damages for related violations of environmental laws or regulations.

Although we are entitled, in certain circumstances, to indemnification from third parties for environmental liabilities relating to assets we acquired from those parties, these contractual indemnification rights are limited, and accordingly, we may be required to bear substantial environmental expenses. However, we believe that through our due diligence process, we identify and manage substantial issues.

Air and Water Emissions. Our operations are subject to the federal Clean Air Act, or CAA, and the federal Clean Water Act, or CWA, and comparable state and local statutes. We anticipate, therefore, that we will incur costs in the next several years for air pollution control equipment and spill prevention measures in connection with maintaining existing facilities and obtaining permits and approvals for any new or acquired facilities. In January 2010, the Environmental Protection Agency, or EPA, published that the effective date of the Spill Prevention, Control, and Countermeasures Rule Amendments would be November 10, 2010. However, on October 7, 2010, the EPA issued an extension to the compliance date to November 10, 2011. While the operations of our pipeline facilities are subject to the rule, we prepared the necessary plans for compliance prior to the November 2011 effective date and are currently in full compliance. In 2009, the EPA published the Greenhouse Gas Recordkeeping and Reporting Rule, which requires applicable facilities to record and report greenhouse gas emissions from combustion sources beginning January 1, 2010. As a part of the reporting rule, in November 2010, the EPA published the requirements for reporting emissions from Petroleum and Natural Gas Systems beginning January 1, 2011. While the operations of our pipelines are subject to the rule, we do not believe that the rule requirements will have a material effect on our operations. Annual emissions from combustion activities in 2010 were reported prior to the September 30, 2011 deadline. Facilities subject to existing Greenhouse Gas Reporting rules reported emissions prior to the March 31, 2012 deadline for 2011 emissions. Facilities subject to the new reporting rules in 2011 reported emissions prior to the September 28, 2012 deadline. On August 23, 2011, the EPA proposed New Source Performance Standards (NSPS), Subpart OOOO, for volatile organic compounds, or VOC, and sulfur dioxide, or SO2, emissions from the Oil and Natural Gas Sector. The final standards were published and became effective on August 16, 2012. The compliance dates range from October 15, 2012, to October 15, 2013, dependent on the affected equipment. The EPA amended the rule to extend compliance dates for certain storage vessels on August 2, 2013, and may issue additional revised rules in the future. There will be additional costs across the industry to attain compliance with the NSPS, Subpart OOOO, but we do not expect a material effect on our financial statements.

The Oil Pollution Act, or OPA, was enacted in 1990 and amends parts of the CWA and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, we could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from our facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements for many of our non-pipeline facilities, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or release. For our liquid pipeline facilities, the OPA imposes requirements for emergency plans to be prepared, submitted and approved by the DOT. For our non-transportation facilities, such as storage tanks that are not integral to pipeline transportation system, the OPA regulations are promulgated by the EPA. We believe that we are in material compliance with these laws and regulations.

Hazardous Substances and Waste Management. The federal Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA (also known as the "Superfund" law) and similar state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of waste disposal sites and companies that disposed or arranged for disposal of hazardous substances found at such sites. We may generate some wastes that fall within the definition of a "hazardous substance." We may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required to clean up and restore sites at which such wastes have been disposed. In addition, 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. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. We have not received any notification that we may be potentially responsible for material cleanup costs under CERCLA or similar state laws.

Site Remediation. We own and operate a number of pipelines, gathering systems, storage facilities and processing facilities that have been used to transport, distribute, store and process natural gas and other petroleum products. Many of our facilities were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under our control. The age of the facilities, combined with the past operating and waste disposal practices, which were standard for the industry and regulatory regime at the time, have resulted in soil and groundwater contamination at some facilities due to historical spills and releases. Such contamination is not unusual within the natural gas and petroleum industry. Historical contamination found on, under or originating from our properties may be subject to CERCLA, the Resource Conservation & Recovery Act and analogous state laws as described above.

Under these laws, we could incur substantial expense to remediate such contamination, including contamination caused by prior owners and operators. In addition, Enbridge Management, as the entity with managerial responsibility for us, could also be liable for such costs to the extent that we are unable to fulfill our obligations. We have conducted site investigations at some of our facilities to assess historical environmental issues, and we are currently addressing soil and groundwater contamination at various facilities through remediation and monitoring programs, with oversight by the applicable governmental agencies where appropriate.

EMPLOYEES

We are managed and operated by the board of directors and executive officers of Midcoast Holdings, L.L.C., our General Partner. Neither we nor our subsidiaries have any employees. Our General Partner is responsible for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our General Partner. Our General Partner and its affiliates had approximately 1,250 employees performing services for our operations as of December 31, 2013. We believe that our General Partner and its affiliates have a satisfactory relationship with those employees.

INSURANCE

Our operations are subject to many hazards inherent in the midstream industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. We are insured under the comprehensive insurance program that is maintained by Enbridge for its subsidiaries through the policy renewal date of May 1, 2014, which includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry. The insurance coverage also includes property insurance coverage on our assets, including earnings interruption resulting from an insurable event, except pipeline assets that are not located at water crossings. In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement the Partnership has entered into with EEP, Enbridge and other Enbridge subsidiaries.

The coverage limits and deductible amounts at December 31, 2013 for our insurance policies:

Insurance Type	Coverage Limits	Deductible Amount
	(in millions)	
Property and business interruption	Up to $700.0	$10.0
General liability	Up to $685.0	$ 0.1
Pollution liability (as included under General Liability)	Up to $685.0	$10.0

We can make no assurance that the insurance coverage we maintain will be available or adequate for any particular risk or loss or that we will be able to maintain adequate insurance in the future at rates we consider reasonable. Although we believe that our assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on our financial position, results of operations and cash flows.

TAXATION

We are not a taxable entity for U.S. federal income tax purposes. Generally, U.S. federal and state income taxes on our taxable income are borne by our individual partners through the allocation of our taxable income. In a limited number of states, an income tax is imposed upon us and generally, not our individual partners. The income tax that we bear is reflected in our consolidated financial statements. The allocation of taxable income to our individual partners may vary substantially from net income reported in our consolidated statements of income.

AVAILABLE INFORMATION

We make available free of charge on or through our Internet website *http://www.midcoastpartners.com* our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements, and if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not part of this report.

Item 1A. Risk Factors

We encourage you to read the risk factors below in connection with the other sections of this Annual Report on Form 10-K.

Risks Related to our Business

We may not generate sufficient distributable cash flow to support the payment of the minimum quarterly distribution, or any distribution, to our unitholders.

In order to support the payment of the targeted minimum quarterly distribution of $0.3125 per unit per quarter, or $1.25 per unit on an annualized basis, we must generate distributable cash flow of approximately $14.4 million per quarter, or approximately $57.7 million per year, based on the number of common and subordinated units and our General Partner interest that are outstanding as of December 31, 2013. We may not generate sufficient distributable cash flow each quarter to support the payment of the targeted minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the volume of natural gas and NGLs we gather and transport and the volume of natural gas we process and treat and NGLs we fractionate;

- the level of production of natural gas and the resultant market prices of natural gas and NGLs;
- realized pricing impacts on our revenue and expenses that are directly subject to commodity price exposure;
- the market prices of natural gas and NGLs relative to one another, which affects our processing margins;
- capacity charges and volumetric fees associated with our transportation services;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies in our geographic markets;
- our operating, maintenance and general and administrative costs, including reimbursements to our General Partner and it's affiliates;
- regulatory action affecting the supply of, or demand for, natural gas, the maximum transportation rates we can charge on our pipelines, our existing contracts, our operating costs or our operating flexibility;
- damage to pipelines, facilities, plants, related equipment and surrounding properties caused by hurricanes, earthquakes, floods, fires, severe weather, explosions and other natural disasters and acts of terrorism, including damage to third party pipelines or facilities upon which we rely for transportation services;
- outages at the processing, treating or fractionation facilities owned by us or third parties caused by mechanical failure and maintenance, construction and other similar activities;
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise; and
- prevailing economic and market conditions.

In addition, the actual amount of distributable cash flow we generate will also depend on other factors, some of which are beyond our control, including:

- the level and timing of capital expenditures we make;
- the cost of acquisitions, if any;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions on distributions contained in our debt agreements;
- the amount of cash reserves established by our General Partner; and
- other business risks affecting our cash levels.

Our financial performance could be adversely affected if our assets are used less. Any decrease in the volumes of natural gas or NGLs that we gather or transport or in the volumes of natural gas that we process and treat, or NGLs that we fractionate, could adversely affect our financial condition, results of operations and cash flows.

Our financial performance depends to a large extent on the volumes of natural gas and NGLs processed, treated, fractionated and transported on our systems. Decreases in the volumes processed, treated, fractionated and transported by our systems can directly and adversely affect our revenues and results of operations. These volumes can be influenced by factors beyond our control, including:

- environmental or other governmental regulations;
- competition;

- weather conditions;
- storage levels;
- alternative energy sources;
- decreased demand for natural gas and NGLs;
- fluctuations in commodity prices, including the price of natural gas and NGL prices;
- economic conditions;
- supply disruptions;
- availability of supply connected to our systems; and
- availability and adequacy of infrastructure to move, treat and process supply into and out of our systems.

The volumes of natural gas and NGLs processed, treated, fractionated and transported on our systems also depends on the supply of natural gas and NGLs from the producing regions that supply these systems. Supply of natural gas and NGLs can be affected by many of the factors listed above, including commodity prices and weather. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas. The primary factors affecting our ability to obtain non-dedicated sources of natural gas include (1) the level of successful drilling activity in our areas of operation, (2) our ability to compete for volumes from successful new wells and (3) our ability to compete successfully for volumes from sources connected to other pipelines. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment. In addition, existing customers may not extend their contracts for a variety of reasons, including a decline in the availability of natural gas from the Mid-Continent, United States Gulf Coast and East Texas producing regions or if the cost of transporting natural gas from other producing regions through other pipelines into the markets served by our systems were to render the delivered cost of natural gas or NGLs on our systems uneconomical. If we are unable to find additional customers to replace lost demand or transportation fees, or if we are unable to find new sources of supply to maintain the current levels of throughput on our systems, our financial condition, results of operations, cash flows and ability to make cash distributions to our unitholders could be materially and adversely affected.

Natural gas and liquid hydrocarbon prices are volatile, and a change in these prices in absolute terms, or an adverse change in the prices of natural gas and liquid hydrocarbons relative to one another, could adversely affect our total segment margin and cash flow and our ability to make cash distributions to our unitholders.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas, liquid hydrocarbons and other commodities have been extremely volatile, and we expect this volatility to continue. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration. For example, if there is a significant change in the relative prices of NGLs and natural gas, it will impact our processing margins, which are a significant component of our ability to generate cash for distribution to our unitholders.

The markets for and prices of natural gas, liquid hydrocarbons and other commodities depend on factors that are beyond our control. These factors include the supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the levels of domestic production and consumer demand;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials;

- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation;
- fluctuations in demand from electric power generators and industrial customers;
- the anticipated future prices of oil, natural gas, NGLs and other commodities;
- worldwide political events, including actions taken by foreign oil and natural gas producing nations;
- worldwide weather events and conditions, including natural disasters and seasonal changes; and
- worldwide economic conditions.

Margins we would have realized from processing activities under certain of our percentage-of-liquids contracts may be reduced if we are unable to process a portion of the natural gas under these contracts.

Under certain of our percentage-of-liquids contracts, we have guaranteed a fixed recovery of NGLs to our customers. To the extent that the volumes of natural gas delivered to us exceed the processing capacity of our processing plants, we may have to pay those customers the fully processed value of their natural gas even though we were unable to process a portion of their natural gas due to capacity limitations, which could reduce the margins we would have otherwise realized from processing activities under these contracts.

Commodity price volatility and risks associated with our hedging activities could adversely affect our cash flow and our ability to make cash distributions to our unitholders.

The prices of natural gas, NGLs and crude oil are inherently volatile, and we expect this volatility will continue. We buy and sell natural gas, NGLs and crude oil in connection with our marketing activities. Our exposure to commodity price volatility is inherent to our natural gas, NGLs and crude oil purchase and resale activities, in addition to our natural gas processing activities. As of December 31, 2013 approximately 57% of our operating revenue, less cost of natural gas and natural gas liquids, was attributable to contracts with some degree of commodity price exposure. In addition, under our keep-whole/wellhead purchase contracts, we have direct exposure to both natural gas and NGL prices because our costs are dependent on the price of natural gas and our revenues are dependent on the price of NGLs.

To the extent that we engage in hedging activities to reduce our commodity price exposure, we may be prevented from realizing the full benefits of price increases above the level of the hedges. However, because we are not fully hedged, we will continue to have commodity price exposure on the unhedged portion of the commodities we receive in-kind as payment for our gathering, processing, treating and transportation services. As a result of this unhedged exposure, a substantial decline in the prices of these commodities could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Additionally, our hedging activities may not be as effective as we intend in reducing the volatility of our future cash flows. Our hedging activities can result in substantial losses if hedging arrangements are imperfect or ineffective and our hedging policies and procedures are not followed properly or do not work as intended. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under the contracts, particularly during periods of weak and volatile economic conditions. In addition, certain of the financial instruments we use to hedge our commodity risk exposures must be accounted for on a mark-to-market basis. This causes periodic earnings volatility due to fluctuations in commodity prices.

Competition may materially and adversely affect our business and results of operations.

We face competition in our gathering, processing and transportation business, as well as in our marketing and logistics business. Some of our competitors are larger companies that have greater financial, managerial and other resources than we do. Our competitors may expand or construct gathering, processing or transportation systems that would create additional competition for the services we provide to our customers. In addition, many of the large wholesale customers served by our natural gas systems have multiple pipelines connected or adjacent to their facilities. Thus, many of these wholesale customers have the ability to purchase natural gas directly from a number of pipelines or from third parties that may hold capacity on other pipelines. Most natural gas producers and owners have alternate gathering and processing facilities available to them. In addition, they have other alternatives, such as building their own gathering facilities or, in some cases, selling their natural gas supplies without processing. Some of our natural gas and NGL marketing competitors have greater financial resources and access to larger supplies of natural gas than those available to us, which could allow those competitors to price their services more aggressively than we do. All of these competitive factors could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

If we fail to balance our purchases of natural gas and our sales of residue gas and NGLs, our exposure to commodity price risk will increase.

We may not be successful in balancing our purchases of natural gas and our sales of residue gas and NGLs. In addition, a producer could fail to deliver promised volumes to us or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause an imbalance between our purchases and sales. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

Our natural gas assets are primarily located in Texas and Oklahoma. Due to our lack of geographic diversification, adverse developments in our existing areas of operation could materially adversely impact our financial condition, results of operations and cash flows and reduce our ability to make cash distributions to our unitholders.

Our natural gas assets are primarily located in Texas and Oklahoma and we intend to focus our future capital expenditures largely on developing our business in these areas. As a result, our financial condition, results of operations and cash flows depend upon the demand for our services in these regions. Due to our lack of geographic diversity, adverse developments in our current segment of the midstream industry or our existing areas of operation could have a significantly greater impact on our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders than if our operations were more diversified.

Future construction and development costs could exceed our forecast, and our cash flow from construction and development projects may not be immediate, which may limit our ability to make cash distributions to our unitholders.

Our strategy to grow our business contemplates significant expenditures for the development, construction or other acquisition of energy infrastructure assets. The construction of new assets involves numerous regulatory, environmental, legal, political, materials and labor cost and operational risks that are difficult to predict and beyond our control. As a result, we may not be able to complete our projects at the costs estimated or within the time periods we have projected. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional equity.

Any or all of these methods may not be available when or in the amounts needed or may adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Our revenues and cash flows may not increase immediately following our expenditure of funds on a particular project. For example, if we build a new pipeline or expand an existing facility, the design, construction, development and installation may occur over an extended period of time and we may not receive any material increase in revenue or cash flow from that project until after it is placed in service and customers begin using the systems. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays or other factors, we may not meet our obligations as they become due, and we may need to reduce or reprioritize our capital budget, sell non-strategic assets, access the capital markets or reassess our level of distributions to unitholders to meet our capital requirements.

Our growth strategies may be unsuccessful if we incorrectly predict operating results, or are unable to identify and complete future acquisitions or organic growth projects and integrate acquired or developed assets or businesses.

The acquisition and development of complementary midstream assets are components of our growth strategy. Acquisitions and organic growth projects present various risks and challenges, including:

- inability to identify attractive acquisition candidates or negotiate acceptable purchase agreements;
- mistaken assumptions about future prices, volumes, revenues and costs, future results of operations or expected cost reductions or other synergies expected to be realized;
- a decrease in liquidity as a result of utilizing significant amounts of available cash or borrowing capacity to finance an acquisition or organic growth project;
- the loss of critical customers or employees at an acquired business;
- the assumption of unknown liabilities for which we may not be fully and adequately indemnified or insured;
- the risk of failing to effectively integrate the operations or management of acquired assets or businesses or a significant delay in such integration; and
- diversion of management’s attention from existing operations.

In addition, we may be unable to identify acquisition targets and consummate acquisitions in the future. A portion of our strategy to grow our business and increase distributions to our unitholders is dependent on our ability to make acquisitions that result in an increase in distributable cash flow. The acquisition component of our growth strategy is based, in large part, on our expectation of ongoing divestitures by EEP of portions of its remaining ownership interest in Midcoast Operating to us over the next four to five years. We do not know when or if any such additional interests will be offered to us to purchase. The consummation and timing of any future acquisitions of these interests will depend upon, among other things, EEP’s willingness to offer these interests for sale to us, our ability to negotiate acceptable purchase agreements with respect to the interests and our ability to obtain financing on acceptable terms, and we can offer no assurance that we will be able to successfully consummate any future acquisition of additional interests in Midcoast Operating. Furthermore, if EEP reduces its ownership interest in us, it may be less willing to sell its remaining ownership interest in Midcoast Operating to us. In addition, there are no restrictions on EEP’s ability to transfer its ownership interest in Midcoast Operating to a third party.

Our gathering, processing and transportation contracts subject us to renewal risks.

We gather, purchase, process, treat, compress, transport and sell most of the natural gas and NGLs on our systems under contracts with terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with fixed-fee or fixed-spread contracts may desire to enter into gathering and transportation contracts under different fee arrangements, or a producer with whom we have a natural gas purchase contract may choose to enter into a transportation contract with us and retain title to its natural gas. In particular, a significant processing contract on our Anadarko system terminated in the third quarter of 2013. To the extent we are unable to renew or replace our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders could be materially and adversely affected.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our financial condition, results of operations and cash flows.

Some of our customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets or reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could materially affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, our operations and financial results could be adversely affected. In addition, total insurance coverage for multiple insurable incidents exceeding coverage limits would be allocated by Enbridge on an equitable basis under an insurance allocation agreement.

Our operations are subject to all of the risks and hazards inherent in the gathering and transportation of natural gas and NGLs and the processing and treating of natural gas and fractionation of NGLs, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards, including those associated with high sulfur content natural gas, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. While we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur. If a significant accident or event occurs for which we are not fully insured, it could adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our indemnification rights, for potential environmental liabilities.

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates, including EEP. The comprehensive insurance program also includes property insurance coverage on our assets, except pipeline assets that are not located at water crossings, and earnings interruption resulting from an insurable event. In the unlikely event that multiple insurable incidents occur that exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the participating Enbridge entities on an equitable basis based on an insurance allocation agreement that we entered into with EEP, Enbridge and another Enbridge subsidiary.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our total segment margin and cash flow and our ability to make cash distributions to our unitholders could be adversely affected.

Our natural gas and NGL gathering and transportation pipelines and natural gas processing and treating facilities and NGL fractionation facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of such third-party pipelines, processing plants, fractionation facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our segment margin and ability to make cash distributions to our unitholders could be adversely affected. For example, following Hurricane Ike in 2008, the Mont Belvieu fractionation complex was shut down for a period of time due to loss of power. This shut down impacted our ability to process natural gas during the period at certain of our processing plants.

Our ability to access capital markets and credit on attractive terms to obtain funding for our capital projects and acquisitions may be limited.

Our ability to fund our capital projects and make acquisitions depends on whether we can access the necessary financing to fund these activities. Domestic and international economic conditions affect the functioning of capital markets and the availability of credit. Adverse economic conditions, such as those that became prevalent during the recessionary period of 2008 and continued through much of 2010, periodically result in weakness and volatility in the capital markets, which in turn can limit, temporarily or for extended periods, our ability to raise capital through equity or debt offerings. Additionally, the availability and cost of obtaining credit commitments from lenders can change as economic conditions and banking regulations reduce the credit that lenders have available or are willing to lend. These conditions, along with significant write-offs in the financial services sector and the re-pricing of market risks, can make it difficult to obtain funding for our capital needs from the capital markets on acceptable economic terms. As a result, we may revise the timing and scope of these projects as necessary to adapt to prevailing market and economic conditions or ability to make distributions.

Due to these factors, we cannot be certain that funding for our capital needs will be available from bank credit arrangements or capital markets on acceptable terms, if needed and to the extent required. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions and construction projects, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Debt we or Midcoast Operating incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

We borrowed $350.0 million under our revolving credit facility to partially fund a cash distribution to EEP. In addition, Midcoast Operating entered into a working capital credit facility, with EEP as the lender, providing for a borrowing capacity of $250.0 million and a financial support agreement with EEP as the financial services provider, providing for guaranties of, and letters of credit obtained by, EEP on an aggregate amount not to exceed $700.0 million. Our existing and future level of debt, as well as Midcoast Operating's future level of debt, could have important consequences to us, including the following:

- our ability and Midcoast Operating's 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;
- the funds that we or Midcoast Operating have available for operations, future business opportunities and cash distributions to unitholders will be reduced by that portion of our and Midcoast Operating's respective cash flow required to make interest payments on outstanding debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt and Midcoast Operating's debt will depend upon, among other things, our future financial and operating performance, which will 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 any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

A shortage of skilled labor in the midstream natural gas industry could reduce labor productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The gathering and transporting of natural gas and NGLs and the processing and treating of natural gas and fractionating of NGLs requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our General Partner's employees, our results of operations could be materially and adversely affected.

Restrictions in our revolving credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and value of our common units.

Our revolving credit facility limits our ability and Midcoast Operating's ability to, among other things:

- incur or guarantee additional debt;
- make distributions on or redeem or repurchase units or other limited partner interests during the continuance of a default;

- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates other than subsidiaries;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of all or substantially all of our or Midcoast Operating's assets.

Our revolving credit facility contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

The provisions of our revolving credit facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our revolving credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our or Midcoast Operating's debt is accelerated, our assets and Midcoast Operating's assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

To the extent Midcoast Operating seeks a credit rating and receives less than an investment grade credit rating, or EEP terminates the financial support agreement with Midcoast Operating, Midcoast Operating could be required to provide collateral for Midcoast Operating's hedging liabilities.

Currently, Midcoast Operating is party to certain International Swaps and Derivatives Association, Inc., or ISDA®, agreements associated with the derivative financial instruments we use to manage our exposure to fluctuations in commodity prices. These ISDA® agreements require Midcoast Operating to provide assurances of performance if counterparties' exposure to Midcoast Operating exceeds certain levels or thresholds. EEP generally provides letters of credit on Midcoast Operating's behalf to satisfy such requirements. At the close of our initial public offering, EEP entered into a financial support agreement with Midcoast Operating under which, during the term of the agreement, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under derivative agreements and natural gas and NGL purchase agreements. Under the financial support agreement, EEP's support of Midcoast Operating's obligations will terminate on the earlier to occur of (1) the fourth anniversary of the closing of the offering and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in us), less than 20% of the total outstanding limited partner interest in Midcoast Operating.

Without an investment grade credit rating or financial support from EEP, we expect that Midcoast Operating will be required to provide letters of credit, cash collateral or other financial assurance with respect to new derivative agreements or purchase agreements that Midcoast Operating enters into. The amounts of any letters of credit Midcoast Operating provides under the terms of Midcoast Operating's ISDA® agreements or other derivative financial instruments or agreements, or otherwise in support of our operations, would reduce the amount that we are able to borrow under our revolving credit facility. To the extent that EEP no longer provides this financial support or if we were otherwise required to guarantee the obligations currently guaranteed by EEP under the financial support agreement, the impact on our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders could be materially and adversely affected.

EEP's credit ratings could adversely affect our ability to grow our business and our ability to obtain credit in the future.

EEP's long-term credit ratings are currently investment grade. Although we will not have any indebtedness rated by any credit rating agency, we may have rated debt in the future. Credit rating agencies will likely consider EEP's debt ratings when assigning ours because of EEP's ownership interest in us and control of our operations. If one or more credit rating agencies were to downgrade the outstanding indebtedness of EEP or us, we could experience an increase in our borrowing costs or difficulty accessing the capital markets. Such a development could adversely affect our financial condition, results of operations and cash flows and our ability to grow our business and to make cash distributions to our unitholders.

Our logistics and marketing operations involve market and regulatory risks.

As part of our logistics and marketing activities, we purchase natural gas and NGLs at prices determined by prevailing market conditions. Following our purchase of natural gas and NGLs, we generally resell the natural gas or NGLs at a higher price under a sales contract that is generally comparable in terms to our purchase contract, including any price escalation provisions. The profitability of our logistics and marketing operations may be affected by the following factors:

- our ability to negotiate on a timely basis commodity purchase and sales agreements in changing markets;
- reluctance of wholesale customers to enter into long-term purchase contracts;
- consumers' willingness to use other fuels when natural gas or NGL prices increase significantly;
- timing of imbalance or volume discrepancy corrections and their impact on financial results;
- the ability of our customers to make timely payment;
- inability to match purchase and sale of natural gas or NGLs on comparable terms; and
- changes in, limitations upon or elimination of the regulatory authorization required for our wholesale sales of natural gas and NGLs in interstate commerce.

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

We use derivative financial instruments to manage the risks associated with market fluctuations in commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are associated with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices or interest rates. These policies cannot, however, eliminate all risk of unauthorized trading and other speculative activity. Although this activity is monitored independently by our risk management function, we remain exposed to the risk of non-compliance with our risk management policies. We can provide no assurance that our risk management function will detect and prevent all unauthorized trading and other violations of our risk management policies and procedures, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could result in significant financial losses and have a material adverse effect on our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Compliance with environmental and operational safety regulations may expose us to significant costs and liabilities.

Our pipeline, gathering, processing and trucking operations are subject to federal, state and local laws and regulations relating to environmental protection and operational and worker safety. Numerous governmental authorities have the power to enforce compliance with the laws and regulations they administer and permits they issue, often requiring difficult and costly actions. Our failure to comply with these laws, regulations and operating permits can result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. Our natural gas gathering, processing and transportation and NGL fractionation operations expose us to the risk of incurring significant environmental costs and liabilities. Additionally, operational modifications, including pipeline restrictions, necessary to comply with regulatory requirements and resulting from our handling of natural gas and liquid hydrocarbons, historical environmental contamination, accidental releases or upsets, regulatory enforcement, litigation or safety and health incidents can also result in significant cost or limit revenues and volumes. We may incur joint and several strict liability under these environmental laws and regulations in connection with discharges or releases of natural gas and liquid hydrocarbons and wastes on, under or from our properties and facilities, many of which have been used for gathering or processing activities for a number of years, often by third parties not under our control. Private parties, including the owners of properties through which our gathering systems pass and facilities where our natural gas and liquid hydrocarbons are handled or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may also incur costs in the future due to changes in environmental and safety laws and regulations, or re-interpretations of enforcement policies or claims for personal, property or environmental damage. We may not be able to recover these costs from insurance or through higher rates.

Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Because our operations, including our processing, treating and fractionation facilities and our compressor stations, emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our facilities, and could delay future permitting. At the federal level, the United States Congress has in the past and may in the future consider legislation to reduce emissions of greenhouse gases. On September 22, 2009, the EPA issued a rule requiring nation-wide reporting of greenhouse gas emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Subsequently, on November 30, 2010, the EPA issued a supplemental rulemaking that expanded the types of industrial sources that are subject to or potentially subject to EPA's mandatory greenhouse gas emissions reporting requirements to include petroleum and natural gas systems.

The April 2010 issuance of regulations to control the greenhouse gas emissions from light duty motor vehicles (the "tailpipe rule") automatically triggered provisions of the Clean Air Act of 1970, as amended, or CAA, that, in general, require stationary source facilities that emit more than 250 tons per year of carbon dioxide equivalent to obtain permits to demonstrate that best practices and technology are being used to minimize greenhouse gas emissions. On May 13, 2010, the EPA issued the "tailoring rule," which served to increase the greenhouse gas emissions threshold that triggers the permitting requirements for major new (and major modifications to existing) stationary sources. Under a phased-in approach, for most purposes, new permitting provisions are required for new facilities that emit 100,000 tons per year or more of carbon dioxide equivalent, or CO2e, and existing facilities making changes that would increase greenhouse gas emissions by 75,000 CO2e. The EPA has also indicated in rulemakings that it may further reduce the current regulatory thresholds for greenhouse gas emissions, making additional sources subject to permitting. On June 26, 2012, in Coalition for Responsible Regulation v. EPA, the U.S. Circuit Court of Appeals for the District of Columbia circuit upheld the bases for the tailoring rule, and ruled that no petitioners had standing to challenge it. On April 18, 2013, the plaintiffs filed a petition for review of that decision by the U.S. Supreme Court.

In addition, more than one-third of the states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap-and-trade programs. Although many of the state-level initiatives have, to date, focused on large sources of greenhouse gas emissions, such as electric power plants, it is possible that in the future sources in states where we operate, such as our gas-fired compressors, could become subject to greenhouse gas-related state regulations. Depending on the particular program, we could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for our services.

Pipeline operations involve numerous risks that may adversely affect our business and financial condition.

Operation of complex pipeline systems, gathering, treating, processing and trucking operations involves many risks, hazards and uncertainties. These events include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of the facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, hurricanes, floods, landslides or other similar events beyond our control. These types of catastrophic events could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, any of which could also result in substantial losses for which insurance may not be sufficient or available and for which we may bear a part or all of the cost. Costs of pipeline seepage over time may be mitigated through insurance, however, if not discovered within the specified insurance time period we would incur full costs for the incident. In addition, we could be subject to significant fines and penalties from regulators in connection with such events. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these catastrophic events could be greater.

Significant portions of our pipeline systems and processing and treating plants have been in service for several decades, which could lead to increased maintenance or repair expenses and downtime associated with our pipelines and processing and treating plants that could have a material adverse effect on our business and operating results.

Significant portions of our pipeline systems and processing and treating plants have been in service for many decades. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems and plants could adversely affect our financial condition and results of operations and cash flows and our ability to make cash distributions to our unitholders.

Measurement adjustments on our pipeline system can materially affect our financial condition.

Natural gas and NGL measurement adjustments occur as part of the normal operating conditions associated with our pipelines. The quantification and resolution of measurement adjustments is complicated by several factors including: (1) the significant quantities (i.e., thousands) of measurement meters that we use throughout our systems, primarily around our gathering and processing assets; (2) varying qualities of natural gas and NGLs in the streams gathered and processed through our systems; and (3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement adjustments that can occur on our systems and may materially affect our results of operations.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A significant portion of our customers' natural gas production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available in 2014. In addition, on October 20, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act, or CWA, to develop standards for wastewater discharges from hydraulic fracturing and other natural gas production activities.

On April 17, 2012, the EPA also approved final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through flaring until 2015, after which reduced emission (or "green") completions must be used. The rules also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants, and certain other equipment. On April 12, 2013, EPA proposed amendments to the rule which would, among other things, provide additional time for recently constructed, modified or reconstructed storage tanks to install emission controls. These rules may require a number of modifications to our customers' and our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our customers, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. For example, on December 13, 2011, the Texas Railroad Commission adopted the Hydraulic Fracturing Chemical Disclosure Rule implementing a state law passed in June 2011, requiring public disclosure of hydraulic fracturing fluid contents for wells drilled under drilling permits issued after February 1, 2012. We cannot predict whether any other legislation will be enacted and if so, what its provisions would be. If additional levels of regulation and permits are required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs, and prohibitions for producers who drill near our pipelines. These factors could reduce the volumes of natural gas and NGLs available to move through our gathering and other systems, which could materially adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders and results of operations.

Changes in, or challenges to, our rates and other terms and conditions of service could have a material adverse effect on our financial condition and results of operations.

The rates charged by several of our pipeline systems are regulated by the Federal Energy Regulatory Commission, or FERC, or state regulatory agencies or both. These regulatory agencies also regulate other terms and conditions of the services these pipeline systems provide, including the types of services we may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service we might propose, the profitability of our pipeline businesses would suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which if delayed could further reduce our cash flow. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services or otherwise adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

The majority of our pipelines are not subject to regulation by the FERC; however, a change in the jurisdictional characterization of our assets, or a change in policy, could result in increased regulation of our assets which could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

The substantial majority of our pipeline assets are gas-gathering facilities or interests in gas-gathering facilities. Unlike interstate gas transportation facilities, natural gas gathering facilities are exempt from the jurisdiction of the FERC under the Natural Gas Act of 1938, or NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some cases non-discriminatory take requirements and complaint-based rate regulation. Although the FERC has not made a formal determination with respect to all of our facilities, we believe that our natural gas pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the Natural Gas Policy Act of 1978, or NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

For the delivery of fuel and other products to our customers, we operate a fleet of specialized trucks and delivery equipment. We are therefore subject to regulation as a motor carrier by the United States Department of Transportation, or DOT, and various state agencies. These federal and state regulatory authorities exercise broad powers, generally governing such activities as the authorization to engage in motor carrier operations, driver licensing and insurance requirements, safety, equipment testing and transportation of hazardous materials. Our trucking operations, including the special modifications we make to our equipment and vehicles to operate in remote, rugged or environmentally sensitive areas, are subject to possible regulatory and legislative changes that may increase our costs. Some of these possible changes include increasingly stringent environmental regulations, fuel emissions limits, changes in the hours of service regulations which govern the amount of time a driver may drive or work in any specific period and limits on vehicle weight and size and other matters.

Our gathering systems and intrastate pipelines are subject to state regulation that could materially and adversely affect our operations and cash flows.

State regulation of gathering facilities includes safety and environmental requirements. Several of our gathering systems are also subject to non-discriminatory take requirements and complaint-based state regulation with respect to our rates and terms and conditions of service. State and local regulation may cause us to incur additional costs or limit our operations, may prevent us from choosing the customers to which we provide service, any or all of which could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

We do not own a majority of the land on which our pipelines are located, which could result in disruptions to our operations.

We do not own a majority of the land on which our pipelines are located, and we are, therefore, subject to the possibility of more onerous terms and increased costs to retain necessary land use if we do not have valid leases or rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies, and some of our agreements may grant us those rights for only a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, financial condition and results of operations and our ability to make cash distributions to our unitholders.

Terrorist or cyber-attacks and threats, escalation of military activity in response to these attacks or acts of war could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, cyber-attacks, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Future terrorist or cyber-attacks, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. We do not maintain specialized insurance for possible liability resulting from a cyber-attack on our assets that may shut down all or part of our business. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

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

In July 2010 federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was enacted. The Dodd-Frank Act provides additional statutory requirements for swap transactions, including oil and gas hedging transactions. These statutory requirements must be implemented through regulations, primarily through rules to be adopted by the Commodity Futures Trading Commission, or the CFTC. The Dodd-Frank Act provisions may change fundamentally the way many swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which many swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. A considerable number of market participants will be newly regulated as swap dealers or major swap participants, with new regulatory capital requirements and other regulations that impose business conduct rules and mandate how they hold collateral or margin for swap transactions. All market participants are subject to new reporting and recordkeeping requirements.

The impact of the Dodd-Frank Act on our hedging activities is uncertain at this time, and the CFTC has not yet promulgated final regulations implementing some of the key provisions. Although we do not believe we will need to register as a swap dealer or major swap participant, and do not believe we will be subject to the new requirements to trade on an exchange or swap execution facility or to clear swaps through a central counterparty, we may have new regulatory burdens. Moreover, the changes to the swap market as a result of Dodd-Frank implementation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps.

Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions in circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore reduce our willingness or ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Our ability to operate our business effectively could be impaired if affiliates of our General Partner fails to attract and retain key management personnel.

We depend on the continuing efforts of the executive officers of our General Partner, all of whom are employees of affiliates of EEP’s general partner. Additionally, neither we nor our subsidiaries have employees. Our General Partner is responsible for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our General Partner, including our President and Principal Executive Officer. The loss of any member of our management or other key employees could have a material adverse effect on our business. Consequently, our ability to operate our business and implement our strategies will depend on the continued ability of affiliates of our General Partner to attract and retain highly skilled management personnel with midstream natural gas industry experience. Competition for these persons in the midstream natural gas industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel.

If we do not ensure that our internal control over financial reporting is effective, we may not be able to prevent intentional misconduct, which could also affect our ability to timely and accurately report our financial results. In January 2012, EEP's management identified a material weakness in internal controls relating to accounting misstatements that resulted from intentional misconduct and collusion by local management responsible for operating Midcoast Operating's trucking and NGL marketing subsidiary.

EEP disclosed in its annual report on Form 10-K for the year ended December 31, 2011 that its management had identified a material weakness in its internal control over financial reporting with respect to Midcoast Operating's trucking and NGL marketing subsidiary. The material weakness related to intentional misconduct and collusion of local management and staff to circumvent EEP's internal control policies which resulted in accounting misstatements. EEP disclosed in its annual report for the year ended December 31, 2012 that it had remediated this material weakness, and EEP's management concluded that EEP maintained effective internal control over financial reporting as of December 31, 2012.

Beginning with the year ending December 31, 2014, our management will be required to provide a report in our annual reports on Form 10-K on the effectiveness of our internal control over financial reporting, among other controls. We and other Enbridge companies maintain systems of disclosure controls and procedures, including internal control over financial reporting, designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, or the Exchange Act, within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our system of controls is designed to provide reasonable, but not absolute, assurance regarding the reliability and integrity of accounting and financial reporting. A control system, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met.

Given these inherent limitations, we may not be able to anticipate or timely identify intentional misconduct to circumvent our internal controls. Our failure to anticipate or timely identify such misconduct could affect our ability to timely file our quarterly and annual reports with the SEC and would subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business, as well as on the trading price of our common units.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Risks Inherent in an Investment in Us

EEP owns and controls our General Partner, which has sole responsibility for conducting our business and managing our operations and has limited duties to us and our unitholders. EEP, Enbridge and our General Partner have conflicts of interest with us and they may favor their own interests to the detriment of us and our other unitholders.

EEP, which is controlled by Enbridge Management through a delegation of control agreement with EEP's general partner, controls our General Partner, and appoint all of the officers and directors of our General Partner, some of whom are also officers or directors of EEP's general partner, Enbridge Management or Enbridge. Although our General Partner has a duty to manage us in a manner that it believes is in the best interests of our partnership and our unitholders, the directors and officers of our General Partner also have a duty to manage our General Partner in a manner that they believe is in the best interests of EEP. Conflicts of interest may arise between EEP, Enbridge and their affiliates, including our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates, including EEP or Enbridge, over our interests and the interests of our common unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires EEP or Enbridge to pursue a business strategy that favors us;
- our General Partner is allowed to take into account the interests of parties other than us, such as EEP and Enbridge, in resolving conflicts of interest;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our General Partner with contractual standards governing its duties limiting our General Partner's liabilities and restricting remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval;
- affiliates of our General Partner, including EEP and Enbridge, may compete with us, and neither our General Partner nor its affiliates have any obligation to present business opportunities to us;
- EEP is under no obligation to offer us any additional interests in Midcoast Operating;
- our General Partner will determine the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our General Partner will determine the amount and timing of many of our cash expenditures and whether a cash expenditure is classified as an expansion capital expenditure, which would not reduce operating surplus, or a maintenance capital expenditure, which would reduce operating surplus. This determination can affect the amount of available cash from operating surplus that is distributed to our unitholders and to our General Partner, the amount of adjusted operating surplus generated in any given period and the ability of the subordinated units to convert into common units;
- our General Partner will determine which costs incurred by it are reimbursable by us;
- our General Partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;
- our partnership agreement permits us to classify up to $45.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus and this cash may be used to fund distributions on our subordinated units or to our General Partner in respect of the general partner interest or the incentive distribution rights;

- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our General Partner intends to limit its liability regarding our contractual and other obligations;
- our General Partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;
- our General Partner controls the enforcement of the obligations that it and its affiliates owe to us;
- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our General Partner may elect to cause us to issue Class B common units to it in connection with a resetting of the target distribution levels related to our General Partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our General Partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our General Partner or any of its affiliates, including its executive officers, directors and owners. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our General Partner, including EEP and Enbridge, and result in less than favorable treatment of us and our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires that we distribute all of our available cash to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Therefore, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we will distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, and we do not anticipate there being limitations in our new credit facility, on our ability to issue additional units, including units ranking senior to the common units as to distribution or liquidation, and our common and subordinated unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any additional units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce our distributable cash flow.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders. However, after the subordination period has ended, our partnership agreement can be amended with the consent of our General Partner and the approval of a majority of the outstanding Class A common units and Class B common units (including Class A common units and Class B common units held by affiliates of our General Partner), voting together as a single class.

Reimbursements due to our General Partner and its affiliates for services provided to us or on our behalf will reduce the amount of cash we have available for distribution to our unitholders. The amount and timing of such reimbursements will be determined by our General Partner.

Prior to making any distributions to our unitholders, we will reimburse our General Partner and its affiliates, including EEP, for expenses they incur and payments they make on our behalf. Our partnership agreement provides that our General Partner will determine in good faith the expenses that are allocable to us. The costs and expenses for which we are required to reimburse our General Partner and its affiliates are not subject to any caps or other limits. The reimbursement of expenses and payment of fees, if any, to our General Partner and its affiliates will reduce the amount of available cash to pay cash distributions to our unitholders.

Because our common units will be yield-oriented securities, increases in interest rates could adversely impact our unit price and our ability to issue equity or incur debt for acquisitions or other purposes.

As with other yield-oriented securities, our unit price is impacted by our level of our cash distributions to our unitholders and the implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and the cost to us of any such issuance or incurrence. In addition, interest rates on our future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

Our partnership agreement replaces our General Partner's fiduciary duties to our limited partners with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary duties to which our General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. In addition, our partnership agreement restricts the remedies available to our limited partners for actions that might constitute breaches of fiduciary duty under applicable state 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. When acting in its individual capacity, our General Partner is entitled 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 or any limited partner. By purchasing a common unit, a unitholder is deemed to have consented to the provisions in our partnership agreement, including the provisions discussed above.

Our partnership agreement limits our General Partner's liabilities and the remedies available to our limited partners for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to our limited partners for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our General Partner, the board of directors of our General Partner or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our General Partner, the board of directors of our General Partner and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in the best interests of our partnership, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

- our General Partner will not have any liability to us or our limited partners for decisions made in its capacity as a General Partner so long as it acted in good faith;
- our General Partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors, as the case may be, 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; and
- our General Partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is approved in accordance with, or otherwise meets the standards set forth in, our partnership agreement.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, our partnership agreement provides that any determination by the board of directors or the conflicts committee of the board of directors of our General Partner must be made in good faith and that our conflicts committee and the board of directors of our General Partner are entitled to a presumption that they acted in good faith. In any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our General Partner may elect to cause us to issue Class B common units to it in connection with a resetting of the target distribution levels related to our General Partner's incentive distribution rights without the approval of the conflicts committee of our General Partner's board or our unitholders. This election may result in lower distributions to our unitholders in certain situations.

Our General Partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters (and the amount of each such distribution did not exceed adjusted operating surplus for each such quarter), to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Furthermore, our General Partner has the right to transfer all or any portion of the incentive distribution rights at any time, and such transferee shall have the same rights as the General Partner relative to resetting target distributions if our General Partner concurs that the tests for resetting target distributions have been fulfilled. Following a reset election by our General Partner, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

In the event of a reset of our minimum quarterly distribution and target distribution levels, our General Partner will be entitled to receive, in the aggregate, a number of Class B common units equal to that number of Class B common units that would have entitled the holder of such units to an aggregate quarterly cash distribution in the two-quarter period prior to the reset election equal to the distribution to our General Partner on the incentive distribution rights in the quarter prior to the reset election prior two quarters. Our General Partner will also be issued the number of General Partner units necessary to maintain its General Partner interest in us that existed immediately prior to the reset election (currently 2.0%). We anticipate that our General Partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per Class A common unit without such conversion; however, it is possible that our General Partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our General Partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our General Partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued Class B common units, which, along with the Class A common units, are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the General Partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. As a result, a reset election may cause holders of our Class A common units and Class B common units to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued Class B common units to our General Partner in connection with resetting the target distribution levels related to our General Partner's incentive distribution rights.

Unitholders have very limited voting rights and even if they are dissatisfied they currently cannot remove our General Partner without its consent.

Unitholders have only limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Unlike holders of stock in a public corporation, unitholders will not have "say-on-pay" advisory voting rights. Unitholders did not elect our General Partner or the board of directors of our General Partners and will have no right to elect our General Partner or the board of directors or our General Partner on an annual or other continuing basis. The directors of our General Partner are chosen by EEP. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The unitholders will be unable initially to remove our General Partner without its consent because our General Partner and its affiliates will own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding Class A common units, Class B common units and subordinated units voting together as a single class is required to remove our General Partner. Our General Partner and its affiliates own approximately 59.1% of the total outstanding Class A common units, Class B common units and subordinated units on an aggregate basis (or 53.0% of our total outstanding Class A common units, Class B common units and subordinated units on an aggregate basis if the underwriters' option to purchase additional common units is exercised in full) (excluding common units purchased by directors and officers of our General Partner and Enbridge Management under our directed unit program). Also, if our General Partner is removed without cause (as defined under our partnership agreement) during the subordination period and common units and subordinated units held by our General Partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into Class B common units and any existing arrearages on the Class A common units will be extinguished. A removal of our General Partner under these circumstances would adversely affect the Class A common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests.

"Cause" is narrowly defined under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the General Partner liable for actual fraud or willful or wanton misconduct in its capacity as our General Partner. Cause does not include most cases of charges of poor management of the business, so the removal of our General Partner because of the unitholders' dissatisfaction with our General Partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units into Class B common units.

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

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any 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 General Partner units or the control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its General Partner units 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 EEP to transfer its membership interest in our General Partner to a third party. The new owner of our General Partner would then be in a position to replace the directors and officers of our General Partner with its own designees.

The incentive distribution rights of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our General Partner transfers its incentive distribution rights to a third party but retains its General Partner interest, our General Partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by our General Partner could reduce the likelihood of EEP selling or contributing additional midstream assets to us, as EEP would have less of an economic incentive to grow our business, which in turn could impact our ability to grow our asset base.

We may issue additional partnership securities without unitholder approval, which would dilute unitholder interests.

At any time, we may issue an unlimited number of additional partnership securities without the approval of our unitholders and our existing unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such limited partner interests. Further, there are no limitations in our partnership agreement on our ability to issue partnership securities that rank equal or senior to our common units as to distributions or in liquidation or that have special voting rights and other rights. The issuance by us of additional common units or other partnership securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash we have available to distribute on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by holders of our common units will increase;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total cash available for distribution, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

EEP may sell our units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of December 31, 2013 EEP holds 1,335,056 Class A common units and 22,610,056 subordinated units. All of the subordinated units will convert into Class B common units on a one-for-one basis at the end of the subordination period and may convert earlier under certain circumstances. Additionally, we have agreed to provide EEP with certain registration rights under applicable securities laws.

Our General Partner's discretion in establishing cash reserves may reduce the amount of cash we have available to distribute to unitholders.

Our partnership agreement requires our General Partner to deduct from operating surplus the cash reserves that it determines are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash we have available to distribute to our unitholders.

Our General Partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 80% of our then-outstanding Class A common units, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us to acquire all, but not less than all, of the Class A common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of our Class A common units over the 20 trading days preceding the date that is three business days before the General Partner exercises this right and (2) the highest per-unit price paid by our General Partner or any of its affiliates for Class A common units during the 90-day period preceding the date such notice is first mailed. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your 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 this limited call right. There is no restriction in our partnership agreement that prevents our General Partner from issuing additional Class A common units and exercising its limited call right. If our General Partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. 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 jurisdictions. You could be liable for any or all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace our General Partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

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 you if the distribution would cause our liabilities to exceed the fair value of our assets. 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. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

Our partnership agreement will designate the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which would limit our unitholders' ability to choose the judicial forum for disputes with us or our General Partner's directors, officers or other employees.

Our partnership agreement provides, that, with certain limited exceptions, the Court of Chancery of the State of Delaware will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty owed by any of our, or our General Partner's, directors, officers, or other employees, or owed by our General Partner, to us or our partners, (4) asserting a claim against us arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in our common units is deemed to have received notice of and consented to the foregoing provisions. Although we believe this choice of forum provision benefits us by providing increased consistency in the application of Delaware law in the types of lawsuits to which it applies, the provision may have the effect of discouraging lawsuits against us and our General Partner's directors and officers. The enforceability of similar choice of forum provisions in other companies' certificates of incorporation or similar governing documents has been challenged in legal proceedings and it is possible that in connection with any action a court could find the choice of forum provisions contained in our partnership agreement to be inapplicable or unenforceable in such action. If a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition and results of operations and our ability to make cash distributions to our unitholders.

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Our Class A common units are listed on the NYSE. Because we are a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our General Partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, or if we were otherwise subjected to a material amount of additional entity-level taxation for state tax purposes, then our distributable cash flow to our unitholders would be substantially reduced.

The anticipated after-tax economic 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 a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a publicly-traded partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our distributable cash flow would be substantially reduced. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash we have available for distribution to you. Therefore, if we were treated as a corporation for federal income tax purposes or otherwise subjected to a material amount of entity-level taxation for state tax purposes, there would be material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels may be adjusted to reflect the impact of that law on us.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

Our unitholders' share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our distributable cash flow to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we have taken or may take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our positions and such positions may not ultimately be sustained. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our distributable cash flow.

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

If our unitholders sell common units, they will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price received is less than the original cost. Furthermore, a substantial portion of the amount realized on any sale of common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income, or UBTI, 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 federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. Our counsel is unable to opine as to the validity of such filing positions. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. Recently, however, the U.S. Treasury Department issued proposed regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are loaned to a "short seller" to effect 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 federal income tax purposes as a partner with respect to those common units during the period of the loan and may be required to recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may be required to 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. 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 Class A common units.

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

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

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

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections, including a new election under Section 754 of the

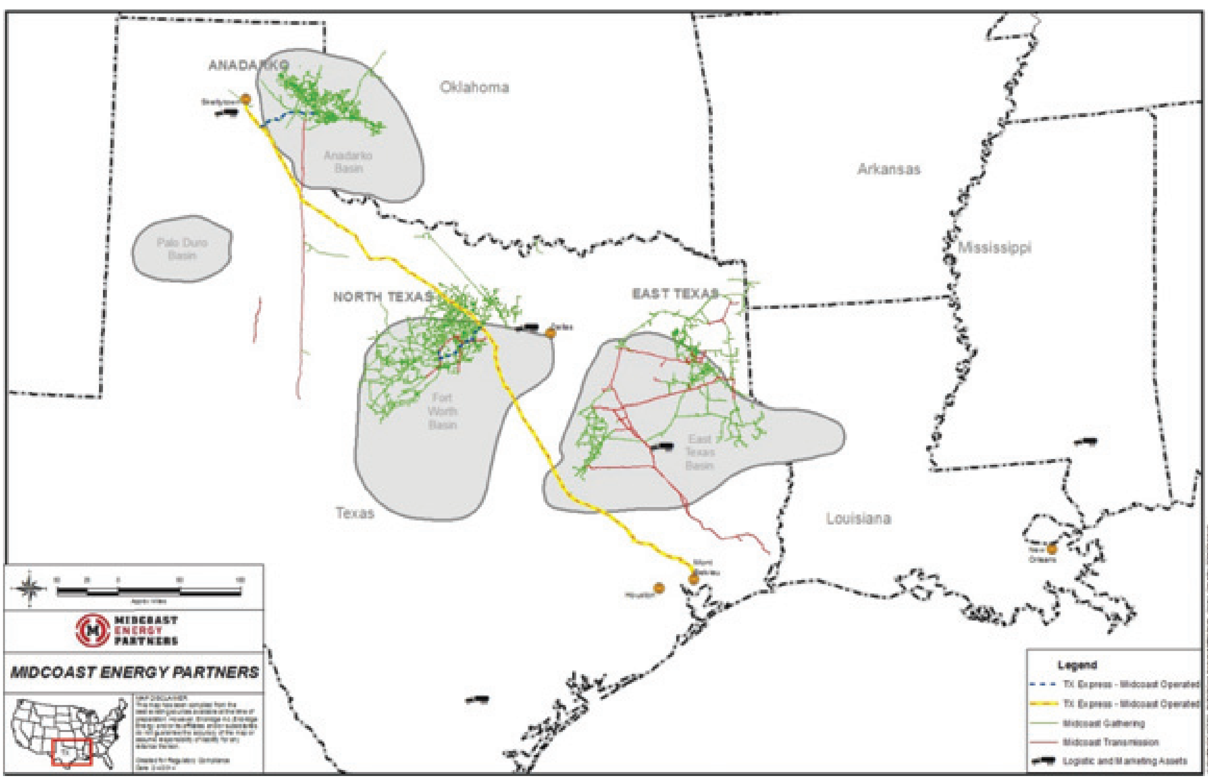
Internal Revenue Code and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if they do not live in any of those jurisdictions. Our 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, our unitholders may be subject to penalties for failure to comply with those requirements. We are now conducting business in over 35 states. Most of these states currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units. Please consult your tax advisor.

Item 2. Properties

The map below presents the location of our current natural gas systems assets, projects being constructed and joint ventures. This map also depicts some assets owned or under development by us to provide an understanding of how they relate to our business.



A description of these properties of our natural gas systems are included in Item 1. *Business*, which is incorporated herein by reference.

In general, our systems are located on land owned by others and are operated under perpetual easements and rights-of-way, licenses, leases or permits that have been granted by private land owners, public authorities, railways or public utilities. Our natural gas systems have natural gas compressor stations, processing plants and treating plants, the vast majority of which are located on land that is owned by us, with the remainder used by us under easements, leases or permits.

Titles to our properties acquired in our natural gas systems are subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

Substantially all of our pipelines are constructed on rights-of-way granted by the record owners of the property. In some instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, and state highways and, in some instances, these permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. Although such revocations are unlikely to be exercised, in nearly all instances continued payment of rentals and license fees, or relocations to accommodate a public authority or railroad ensures continued operation of the affected system. In some states and under some circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines. Under our omnibus agreement, EEP will indemnify us for any failure to have certain rights-of-way, consents, licenses and permits necessary to own and operate our assets in substantially the same manner that they were owned and operated prior to our IPO. EEP's indemnification obligation will be limited to losses for which we notify EEP prior to the third anniversary of the closing our IPO and will be subject to a $500,000 aggregate deductible before we are entitled to indemnification. EEP's indemnification obligations under the omnibus agreement are subject to a $15.0 million aggregate cap.

Item 3. Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition. The disclosures included in Part II, Item 8. *Financial Statements and Supplementary Data*, under Note 13. *Commitments and Contingencies,* address the matters required by this item and are incorporated herein by reference. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Item 4. Mine Safety Disclosures

None.

PART II

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

Our Class A common units are listed and traded on the NYSE, the principal market for the Class A common units, under the symbol MEP. The quarterly price ranges per Class A common unit are summarized as follows:

	First	Second	Third	Fourth
2013 Quarters				
High	$—	$—	$—	$20.30
Low	$—	$—	$—	$16.96

On February 14, 2014, the last reported sales price of our Class A common units on the NYSE was $20.34. At January 31, 2014, there were approximately 2,487 Class A common unitholders, of which there were approximately 3 registered Class A common unitholders of record. There is no established public trading market for our subordinated units, all of which are held EEP.

There were no distributions paid in 2013 following our initial public offering. Under our current cash distribution policy, we intend to make a minimum quarterly distribution to the holders of our Class A common units and subordinated units of $0.3125 per unit, or $1.25 per unit on an annualized basis, to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including the payment of expenses to our General Partner and its affiliates. Our current cash distribution policy is also subject to certain restrictions, as well as the considerable discretion of our General Partner in determining the amount of our available cash each quarter. These restrictions include restrictions under our Credit Agreement, general partner discretion to establish reserves and to take other actions provided by our limited partnership agreement, and performance of our subsidiaries. For further information about distributions and about these and other limitations and risks related to distributions, please read Item 1A. *Risk Factors* and Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Distributions.*

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table provides information as of December 31, 2013 with respect to Class A common units that may be issued under the 2013 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or our LTIP:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[(1)]	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans[(2)]
Equity compensation plans approved by security holders	N/A	N/A	3,750,000
Equity compensation plans not approved by security holders	—	—	—
Total			3,750,000

(1) We have not previously granted equity incentive awards in us to any person pursuant to the LTIP

(2) Reflects the Class A common units available for issuance pursuant to the LTIP

ISSUER PURCHASES OF EQUITY SECURITIES

The following table provides information as of December 31, 2013 with respect to Class A common units that were purchased by Midcoast Energy Partners, L.P. from Enbridge Energy Partners:

Period	Total number of units purchased	Average price paid per unit	Total number of units purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of units that may yet be purchased under the plans or programs
October 1—October 31	—	$ —	—	—
November 1—November 30[1]	2,775,000	$16.94	—	—
December 1—December 31	—	$ —	—	—
Total	2,775,000	$16.94	—	—

(1) Pursuant to the Contribution, Conveyance and Assumption Agreement, dated as of November 13, 2013, by and among EEP, MEP, Midcoast Holdings, Midcoast Operating and Midcoast OLP GP, L.L.C., 2,775,000 Class A common units were purchased by MEP from EEP with the proceeds from the over-allotment option exercise related to the Offering.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data of Midcoast Energy Partners, L.P. and our Predecessor. The table is derived, and should be read in conjunction with, our audited consolidated financial statements and notes thereto included in Item 8. *Financial Statements and Supplementary Data*. See also Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

	December 31,				
	2013	**2012(1)**	**2011(1)**	**2010(1)**	**2009(1)**
	(in millions, except per unit amounts)				
Income Statement Data:(2)					
Operating revenues	$5,593.6	$5,357.9	$7,828.2	$6,654.3	$4,563.4
Operating expenses	5,528.5	5,186.5	7,608.9	6,497.3	4,407.5
Operating income	65.1	171.4	219.3	157.0	155.9
Interest expense	1.7	—	—	—	—
Other income (expense)	(1.2)	(0.1)	2.8	3.0	1.0
Income (loss) from discontinued operations	—	—	—	—	(64.9)
Income tax expense	8.3	3.8	2.9	2.6	4.0
Net Income	$ 53.9	$ 167.5	$ 219.2	$ 157.4	$ 88.0
Predecessor income prior to initial public offering (from January 1, 2013 through November 12, 2013)	$ 56.3				
Net loss subsequent to initial public offering to Midcoast Energy Partners, L.P. (from November 13, 2013 through December 31, 2013)	$ (2.4)				
Net loss attributable to noncontrolling interest subsequent to initial public offering	$ (0.6)				
Net loss attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P. subsequent to initial public offering	$ (1.8)				
Net income attributable to limited partner ownership interest(5)	$ 19.7	$ 64.0	$ 83.8	$ 60.2	$ 33.6
Income (loss) from continuing operations per limited partner unit (basic and diluted)(5)	$ 0.68	$ 2.40	$ 3.14	$ 2.26	$ 1.26
Cash distributions paid per limited partner unit outstanding(5)	$ 1.25	$ 1.25	$ 1.25	$ 1.25	$ 1.25
Financial Position Data (at year end):(2)(3)(4)					
Property, plant and equipment, net	$4,082.3	$3,963.0	$3,651.3	$3,320.6	$2,664.5
Total assets	6,036.4	5,667.4	5,134.6	4,802.6	3,522.6
Long-term debt, excluding current maturities	335.0	—	—	—	—
Partners' capital:					
Predecessor partner interest	—	4,707.1	4,277.8	3,994.1	3,025.0
Class A common units	495.3	—	—	—	—
Subordinated units	1,035.1	—	—	—	—
General Partner	42.2	—	—	—	—
Accumulated other comprehensive income (loss)	(3.1)	7.1	(28.7)	(51.4)	(56.4)
Noncontrolling interest	2,983.2	—	—	—	—
Partners' capital	$4,552.7	$4,714.2	$4,249.1	$3,942.7	$2,968.6
Cash Flow Data:(2)(3)(4)					
Cash flows provided by operating activities	$ 420.9	$ 352.7	$ 415.6	$ 172.4	$ 383.1
Cash flows used in investing activities	522.3	614.5	480.1	984.1	13.9
Cash flows provided by (used in) financing activities	106.3	261.8	64.5	811.7	(369.2)
Additions to property, plant and equipment, acquisitions and investment in joint venture included in investing activities, net of cash acquired	462.9	621.1	484.0	1,002.2	144.3

(1) Represents Midcoast Operating, L.P. Predecessor historical information.

(2) Our income statement, financial position and cash flow data reflect the following significant acquisitions and dispositions:

Date of Acquisition / Disposition	Description of Acquisition / Disposition
September 2010	Acquisition of the Elk City system in Oklahoma and Texas.
November 2009	Disposition of natural gas pipelines located predominately outside of Texas.
January 2009	Disposition of an offshore natural gas pipeline.

(3) Our financial position and cash flow data include the effect of the following public limited partner unit issuances:

Date of Unit Issuance	Class of Limited Partnership Interest	Number of Units Issued	Net Proceeds Including General Partner Contribution
December 2013	Class A	2,775,000	$ 47.0
November 2013	Class A	18,500,000	$304.5

- The 2013 equity issuances represent the Offering.

(4) Represents $323.4 million we borrowed under a newly established $850.0 million revolving credit facility and remitted to EEP as consideration for a portion of the 39% controlling interest in Midcoast Operating contributed to us.

(5) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% retained by EEP.

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

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes beginning in Item 8. *Financial Statements and Supplementary Data* of this Annual Report on Form 10-K. Unless the context otherwise requires, references to the Predecessor, we, our, us, or like terms, when used in a historical context (periods prior to November 13, 2013), refer to Midcoast Operating, L.P. References in this report to Midcoast Energy Partners, the Partnership, MEP, we, our, us, or like terms used in the present tense or prospectively (periods beginning on or after November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries.

Initial Public Offering

On November 13, 2013, we completed our initial public offering, or the Offering, of 18,500,000 Class A common units representing limited partner interests. (2,775,000 additional Class A common units were issued on December 9, 2013 pursuant to the underwriters' exercise of the over-allotment option we granted to them in connection with the Offering.) On the same date, in connection with the closing of the Offering, certain transactions, among others, occurred pursuant to which EEP effectively conveyed to us: (1) all of its limited liability company interests in Midcoast OLP GP, L.L.C. (the general partner of Midcoast Operating, L.P., or Midcoast Operating); and (2) an approximate 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units, MEP Subordinated Units, a right to receive $323.4 million in cash, and approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the conveyed businesses. MEP received proceeds (net of underwriting discounts, structuring fees and offering expenses) from the Offering of approximately $354.9 million including net proceeds of $47.0 million from the underwriters' exercise of the over-allotment option we granted to them in connection with the Offering. MEP used the net proceeds to distribute approximately $304.5 million to EEP, to pay approximately $3.4 million in revolving credit facility origination and commitment fees and used approximately $47.0 million to redeem 2,775,000 Class A common units from EEP. Following the completion of the Offering, EEP continues to own crude oil and liquid petroleum assets and a 61% non-controlling interest in Midcoast Operating. EEP also retained a significant interest through its ownership of our general partner, a 52% limited partner interest, after the exercise of the over-allotment option, in us and all of our incentive distribution rights. The Class A common units began trading on November 7, 2013 on the New York Stock Exchange, or NYSE, under the ticker symbol MEP. For information on the various agreements between us and our affiliates see Item 13. *Certain Relationships and Related Transactions and Director Independence.*

Items Affecting the Comparability of Our Financial Results

Our future results of operations may not be comparable to our Predecessor's historical results of operations for the reasons described below:

- Our Predecessor's results of operations historically reflected 100% of the revenues and expenses relating to Midcoast Operating. At the close of the Offering, EEP contributed to us a 39% controlling interest in Midcoast Operating. We currently consolidate the results of operations of Midcoast Operating and then initially record a 61% non-controlling interest deduction for EEP's retained interest in Midcoast Operating. Additionally, although EEP has the option to fund its pro rata share of Midcoast Operating's capital expenditures, to the extent it elects not to do so, we may elect to fund EEP's portion in exchange for additional interests in Midcoast Operating and, as a result, our interest in Midcoast Operating would increase over time.
- Although the allocation methodology under which we will continue to reimburse EEP and its affiliates for the provisions of certain administrative and operational services to Midcoast Operating will not change, $25.0 million in annual amounts payable for general and administrative expenses that were paid by Midcoast Operating historically under its existing services agreements will not be payable by Midcoast Operating going forward.
- We expect to incur an additional $4.0 million of incremental annual general and administrative expenses as a result of being a separate publicly traded partnership, 100% of which will be attributable to us.
- EEP no longer provides financial support to Midcoast Operating at no cost and we are responsible for our proportionate share of the annual expenses attributable to a financial support agreement that Midcoast Operating entered into with EEP. During the term of the financial support agreement, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under certain legacy hedges and key customer natural gas and NGL purchase agreements. The annual cost that Midcoast Operating incurs under the financial support agreement, which we estimate will initially range from approximately $4.0 million to $5.0 million, is based on the cumulative average amount of letters of credit and guarantees that EEP may provide on Midcoast Operating's behalf multiplied by a 2.5% annual fee. Based on our 39% controlling interest in Midcoast Operating, we estimate that our proportionate share of these annual expenses will initially range from approximately $1.6 million to $2.0 million. EEP has historically provided such financial support to Midcoast Operating at no cost. Without such financial support from EEP, we expect that Midcoast Operating would be required to provide letters of credit, cash collateral or other financial support with respect to these agreements or similar agreements it enters into in the future. For more information regarding our financial support agreement and the calculation of this annual fee, please read "Liquidity and Capital Resources—Financial Support Agreement."
- We incur interest expense under our revolving credit facility, Midcoast Operating's working capital credit facility and other borrowing arrangements we may enter into from time to time. Prior to our acquiring control of our Predecessor, it was a wholly owned subsidiary of EEP and, as such, did not incur any direct interest expense from third parties and only recognized intercompany interest expense to the extent such amounts were capitalized as part of its construction projects.

RESULTS OF OPERATIONS—OVERVIEW

Our business primarily consists of gathering unprocessed and untreated natural gas from wellhead locations and other receipt points on our systems, processing the natural gas to remove NGLs and impurities at our processing and treating facilities and transporting the processed natural gas and NGLs to intrastate and interstate pipelines for transportation to various customers and market outlets. In addition, we also market natural gas and NGLs to wholesale customers.

Our financial condition and results of operations are subject to variability from multiple factors, including:

- the volumes of natural gas and NGLs that we gather, process and transport on our systems;
- the price of natural gas and NGLs that we pay for and receive in connection with the services we provide;
- our ability to replace or renew existing contracts, such as our ability to replace a significant processing contract on our Anadarko system that terminated during the third quarter of 2013; and
- the supply and demand for natural gas and NGLs.

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing. We have established these reporting segments as strategic business units to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31, 2013, 2012 and 2011.

	December 31,		
	2013	2012	2011
		(in millions)	
Operating Income (loss)			
Gathering, Processing and Transportation	$70.2	$191.5	$195.3
Logistics and Marketing	(5.1)	(19.9)	24.1
Corporate, operating and administrative	—	(0.2)	(0.1)
Total Operating Income	65.1	171.4	219.3
Other income (expense)	(1.2)	(0.1)	2.8
Interest expense	1.7	—	—
Income tax expense	8.3	3.8	2.9
Net income	$53.9	$167.5	$219.2
Less: Predecessor income prior to initial public offering (from January 1, 2013 through November 12, 2013)	56.3		
Net income subsequent to initial public offering to Midcoast Energy Partners, L.P. (from November 13, 2013 through December 31, 2013)	(2.4)		
Less: Net income attributable to noncontrolling interest subsequent to initial public offering	(0.6)		
Net income attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P. subsequent to initial public offering	$ (1.8)		

Contractual arrangements in our Gathering, Processing and Transportation segment and our Logistics and Marketing segment expose us to market risks associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices, which can be significant during periods of price volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. Revenues for our gathering, processing and transportation business are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our systems; the volumes of NGLs sold; and the level of natural gas, NGL and condensate prices. The segment gross margin of our gathering, processing and transportation business, which we define as revenue generated from gathering, processing and transportation operations less the cost of natural gas and natural gas liquids purchases, is derived from the compensation we receive from customers in the form of fees or commodities we receive for providing our services, in addition to the proceeds we receive for the sales of natural gas, NGLs and condensate to affiliates and third parties.

The operating income of our Gathering, Processing and Transportation segment for the year ended December 31, 2013 decreased $121.3 million, as compared with the same period in 2012, primarily due to the following:

- Decreased segment gross margin of approximately $57.0 million due to reduced pricing spreads between the NGLs purchased at Conway and the NGLs sold at Mont Belvieu market hubs;
- Decreased segment gross margin from keep-whole processing earnings of $27.1 million due to a decline in total NGL production;
- Decreased segment gross margin of approximately $26.0 million due to reduced production volumes;
- Decreased segment gross margin of approximately $4.0 million due to changes in physical measurement adjustments; and
- Increased depreciation expense of $7.7 million due to additional assets that were placed into service during 2012 and 2013.

The above factors were partially offset for the year ended December 31, 2013, as compared with the year ended December 31, 2012, due to:

- Decreased current year costs of $4.3 million for the prior year write down of surplus materials associated with deferred portions of a development project on our East Texas system.

Logistics and Marketing

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business, thereby enhancing our competitive position. In addition, our logistics and marketing services provide our customers with the opportunity to receive enhanced economics by providing access to premium markets through the transportation capacity and other assets we control. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from pipeline systems and processing plants and sells and delivers them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants.

The operating income of our Logistics and Marketing segment for the year ended December 31, 2013 increased $14.8 million, as compared with the year ended December 31, 2012, primarily due to a more favorable natural gas and NGL pricing environment and reduced expenses for the year ended December 31, 2013, when compared to the year ended December 31, 2012.

Derivative Transactions and Hedging Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as "Operating revenue" and "Cost of natural gas and natural gas liquids".

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net changes in fair value associated with our derivative financial instruments:

	December 31,		
	2013	2012	2011
	(in millions)		
Gathering, Processing and Transportation segment			
Hedge ineffectiveness	$ 3.3	$ 3.1	$ (5.3)
Non-qualified hedges	3.3	0.6	14.8
Logistics and Marketing segment			
Non-qualified hedges	(9.6)	(2.5)	7.0
Derivative fair value net gains (losses)	$(3.0)	$ 1.2	$16.5

RESULTS OF OPERATIONS—BY SEGMENT

Gathering, Processing and Transportation

Our Gathering, Processing and Transportation segment consists of natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. Our gathering, processing and transportation business consists of the following four systems:

- *Anadarko system:* Approximately 3,100 miles of natural gas gathering and transportation pipelines, approximately 58 miles of NGL pipelines, nine active natural gas processing plants, three standby natural gas processing plants and one standby treating plant located in the Anadarko basin.
- *East Texas system:* Approximately 3,900 miles of natural gas gathering and transportation pipelines, approximately 108 miles of NGL pipelines, six active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, eight active natural gas treating plants, three standby natural gas treating plants and one fractionation facility located in the East Texas basin.
- *North Texas system:* Approximately 4,600 miles of natural gas gathering and transportation pipelines, approximately 60 miles of NGL pipelines, six active natural gas processing plants and one standby natural gas processing plant located in the Fort Worth basin.
- *Texas Express NGL system:* A 35% interest in an approximately 580-mile NGL intrastate transportation mainline and a related NGL gathering system that consists of approximately 116 miles of gathering lines.

The Texas Express NGL system commenced startup operations during the fourth quarter of 2013. During startup operations, revenue recognition is delayed while the system is being filled with NGLs but operating costs are recognized. Additionally, the Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. These factors in combination contributed to a $1.0 million equity loss for the year ended December 31, 2013, which we recognized in "Other income (expense)" on our consolidated statement of income.

The following tables set forth the operating results of our Gathering, Processing and Transportation segment and the approximate average daily volumes of natural gas throughput and NGLs produced on our systems for the years ended December 31, 2013, 2012, and 2011.

	December 31,		
	2013	2012	2011
		(in millions)	
Operating revenues	$ 729.0	$ 818.0	$ 914.2
Cost of natural gas and natural gas liquids	157.6	131.2	271.1
Segment gross margin	571.4	686.8	643.1
Operating and maintenance	278.9	281.5	241.0
General and administrative	86.6	85.8	71.6
Depreciation and amortization	135.7	128.0	135.2
Operating expenses	501.2	495.3	447.8
Operating income	$ 70.2	$ 191.5	$ 195.3
Operating Statistics (MMBtu/d)			
East Texas	1,153,000	1,266,000	1,378,000
Anadarko[(1)]	949,000	1,017,000	1,013,000
North Texas	317,000	330,000	337,000
Total	2,419,000	2,613,000	2,728,000
NGL Production (Bpd)	88,236	97,428	87,376

(1) Average daily volumes for the years ended December 31, 2013, 2012 and 2011 include 280,000 MMBtu/d, 255,000 MMBtu/d, and 251,000 MMBtu/d, respectively, of volumes associated with our Elk City system.

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectability is reasonably assured. We generate revenues and segment gross margin principally under the following types of arrangements:

Equity Investment in Joint Venture

Our natural gas and NGLs business includes our 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties, representing a 580-mile NGL intrastate transportation pipeline and a related NGL gathering system. We use the equity method of accounting for our 35% joint venture interest in the Texas Express NGL system as a result of our ability to significantly influence the operating activities, but insufficient ability to control these activities without the participation of a majority of the other members.

Fee-Based Arrangements

In a fee-based arrangement, we receive a fee per Mcf of natural gas processed or per gallon of NGLs produced. Under this arrangement, we have no direct commodity price exposure. We receive fee-based revenue for services, such as compression fees, gathering fees and treating fees that are recognized when volumes are received on our systems. Additionally, revenues that are derived from transmission services consist of reservation fees charged for transportation of natural gas on some of our intrastate pipeline systems. Customers paying these fees typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transportation volumes. Reservation fees are required to be paid whether or not the shipper delivers the volumes, thus referred to as a ship-or-pay arrangement. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transportation services.

Commodity-Based Arrangements

We also generate revenue and segment gross margin under other types of service arrangements with customers. These arrangements expose us to commodity price risk, which we mitigate to a substantial degree with the use of derivative financial instruments to hedge open positions in these commodities. We hedge a significant amount of our exposure to commodity price risk to support the stability of our cash flows. We provide additional information in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk - Commodity Price Risk* and Note 14. *Derivative Financial Instruments and Hedging Activities* of our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* of this report about the derivative activities we use to mitigate our exposure to commodity price risk.

The commodity-based service contracts we have with customers are categorized as follows:

- *Percentage-of-Proceeds Contracts*—Under these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we can sell at market prices and retain the proceeds as our compensation. This type of arrangement exposes us to commodity price risk, as the revenues from percentage-of-proceeds contracts directly correlate with the market prices of the applicable commodities that we receive.
- *Percentage-of-Liquids Contracts*—Under these contracts, we receive a negotiated percentage of the NGLs extracted from natural gas that require processing, which we can then sell at market prices and retain the proceeds as our compensation. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGLs produced. This type of contract may also require us to provide the customer with a guaranteed NGL recovery percentage regardless of actual NGL production. Since revenues from percentage-of-liquids contracts directly correlate with the market price of NGLs, this type of arrangement also exposes us to commodity price risk.
- *Percentage-of-Index Contracts*—Under these contracts, we purchase raw natural gas at a negotiated percentage of an agreed upon index price. We then resell the natural gas, generally for the index price, and keep the difference as our compensation.
- *Keep-Whole Contracts*—Under these contracts, we gather or purchase raw natural gas from the customer. We extract and retain the NGLs produced during processing for our own account, which we then sell at market prices. In instances where we purchase raw natural gas at the wellhead, we may also sell the resulting residue natural gas for our own account at market prices. In those instances when we gather and process raw natural gas for the customer’s account, we generally must return to the customer residue natural gas with an energy content equivalent to the original raw natural gas we received, as measured in British thermal units, or Btu. This type of arrangement has the highest commodity price exposure because our costs are dependent on the price of natural gas purchased and our revenues are dependent on the price of NGLs sold. As a result, we benefit from these types of contracts when the value of the NGLs is high relative to the cost of the natural gas and are disadvantaged when the cost of the natural gas is high relative to the value of the NGLs.

Under the terms of each of our commodity-based service contracts, we retain natural gas and NGLs as our compensation for providing these customers with our services. As of December 31, 2013, we are exposed to fluctuations in commodity prices in the near term on approximately 35% to 40% of the natural gas, NGLs and condensate we expect to receive as compensation for our services. Due to this unhedged commodity price exposure, our segment gross margin, representing revenue less cost of natural gas, generally increases when the prices of these commodities are rising and generally decreases when the prices are declining. As a result of entering into these derivative instruments, we have largely fixed the amount of cash that we will pay and receive in the future when we sell the residue gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate. Many of the derivative financial instruments we use do not qualify for hedge accounting. As a result, we record the changes in fair value of the derivative instruments that do not qualify for hedge accounting in our operating results. This accounting treatment produces non-cash gains and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile.

Year ended December 31, 2013 compared with year ended December 31, 2012

The operating income of our Gathering, Processing and Transportation segment for the year ended December 31, 2013 decreased $121.3 million, as compared with the year ended December 31, 2012. The most significant area affected was segment gross margin, which decreased $115.4 million for the year ended December 31, 2013 as compared with the year ended December 31, 2012.

The segment gross margin for our Gathering, Processing and Transportation segment was negatively affected by the reduction in segment gross margin derived from purchasing some of our NGLs at the Conway market hub and selling them at the Mont Belvieu market hub. On our Anadarko system, we purchase some NGLs at Conway hub prices and then have the ability to resell the NGLs at Mont Belvieu hub prices. For the year ended December 31, 2013, the prevailing price for NGLs increased approximately 6% per composite barrel at the Conway pricing hub, and decreased approximately 9% per composite barrel at the Mont Belvieu pricing hub, in each case as compared with the prevailing composite barrel prices for the year ended December 31, 2012. The segment gross margin of our Gathering, Processing and Transportation segment decreased by approximately $57.0 million for the year ended December 31, 2013 when compared with the year ended December 31, 2012 due to the changes in NGL prices between these pricing hubs.

A variable element of the operating results of our Gathering, Processing and Transportation segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to the barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the year ended December 31, 2013 decreased $27.1 million from the year ended December 31, 2012. The decline in keep-whole earnings is the result of a decline in total NGL production.

Reduced production volumes negatively affected segment gross margin by approximately $26.0 million for the year ended December 31, 2013. The average daily volumes of our major systems for the year ended December 31, 2013 decreased by approximately 194,000 MMBtu/d, or 7%, when compared to the year ended December 31, 2012. The average NGL production for the year ended December 31, 2013 decreased by approximately 9,192 Bpd, or 9%, when compared to the year ended December 31, 2012. The decline in volumes is due to reduced drilling activity in our dry gas operating areas, predominately in East Texas, along with a recent trend of dry gas wells that have been drilled but not completed, and the loss of a major customer contract on our Anadarko system, which led to reduced volumes on the system in the second half of 2013. Additionally, extreme weather conditions for the year ended December 31, 2013 as compared to December 31, 2012 also contributed to the reduced volumes. During 2013, two different sustained freezing events negatively impacted volumes flows on our Anadarko, Elk City, and North Texas systems for a seven to ten day time period. Additionally, a localized fire at our Elk City plant took this asset offline on December 6, 2013 and is expected to be back to full capacity in February 2014. Recent shifts in supply and demand fundamentals for NGLs, particularly ethane, have resulted in downward pressure on the current and forward prices for this commodity. As a result of the lower prices for ethane during the year ended December 31, 2013, it was more profitable to operate most of the processing plants on our Anadarko system in ethane rejection mode, which results in lower NGL volumes, since ethane is sold as part of the natural gas stream.

Also contributing to the decrease in segment gross margin for the year ended December 31, 2013 was a decrease of approximately $4.0 million due to changes in physical measurement adjustments for the year ended December 31, 2013 as compared to the year ended December 31, 2012. Physical measurement adjustments routinely occur on our systems as part of our normal operations, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational conditions.

Operating and maintenance costs of our Gathering, Processing and Transportation segment decreased $2.6 million for the year ended December 31, 2013 when compared to the year ended December 31, 2012, primarily due to a $4.3 million prior year write down of surplus materials associated with deferred portions of a development project on our East Texas system that we do not expect to complete until production levels reach a sustainable level to support our expansion activities in the region. There were no similar costs recorded during the year ended December 31, 2013.

Depreciation expense for our Gathering, Processing and Transportation segment increased $7.7 million for the year ended December 31, 2013 compared with the year ended December 31, 2012, due to additional assets that were put in service during 2012 and 2013.

Year ended December 31, 2012 compared with year ended December 31, 2011

The segment gross margin of our Gathering, Processing and Transportation segment for the year ended December 31, 2012 increased by $43.7 million from the year ended December 31, 2011 due to higher NGL production partially offset by lower commodity prices and natural gas volumes, as well as other factors described below. Average natural gas prices declined approximately 31% per MMBtu for the year ended December 31, 2012 compared to the year ended December 31, 2011, based upon the NYMEX Henry Hub pricing index. NGL prices declined approximately 30% and 28% per composite barrel for the year ended December 31, 2012 compared to the year ended December 31, 2011, based upon average pricing at the Conway and Mont Belvieu market hubs, respectively.

We increased the processing capacity of our Anadarko system when we completed our Allison processing plant in November 2011 and obtained additional NGL takeaway capacity in April 2012, which enabled us to effectively process more natural gas and produce more NGLs on the system. Despite the decline in NGL prices, our processing segment gross margin on this system for the year ended December 31, 2012 increased by $49.2 million over the year ended December 31, 2011. The increase in processing segment gross margin was attributable to our increased ability to effectively process natural gas and produce NGLs due to the completion of our Allison processing plant. Partially offsetting the increase in segment gross margin derived from the additional processing capacity was an approximate $22.4 million decrease in segment gross margin we made from purchasing some of our NGLs at the Conway market hub and selling them at the Mont Belvieu market hub during the year ended December 31, 2012 compared with the year ended December 31, 2011.

Average daily natural gas volumes on our systems for the year ended December 31, 2012 decreased approximately 115,000 MMBtu/d, or 4.2%, compared to the year ended December 31, 2011 due to reduced drilling in dry gas areas and declines in recently added wells, primarily on our East Texas system. This volume decrease was partially offset by an increase in volumes due to more favorable winter weather conditions than those that adversely impacted natural gas production in 2011. NGL production during the year ended December 31, 2012 increased approximately 10,052 Bpd, or 11.5%, compared to the year ended December 31, 2011 due to producers focusing their drilling activities on more liquids-rich formations within our operating areas, as well as the completion of our Allison processing plant.

For the year ended December 31, 2012, segment gross margin increased $13.0 million when compared with the year ended December 31, 2011 due to additional fee-based revenue generated by each of our systems. The additional fee-based revenue was primarily attributable to additional compression fees, increased charges for gathering services and additional volumes from the recent expansion of our East Texas system into the Haynesville Shale.

Segment gross margin also increased $11.2 million for the year ended December 31, 2012 as compared with the year ended December 31, 2011, due to improved recoveries of NGLs resulting from enhancements we made to increase the operating efficiency of several of the processing plants on our Anadarko system, a higher NGL content in the natural gas stream for natural gas we processed and the completion of our Allison processing plant.

Our segment gross margin was negatively affected by non-cash, mark-to-market net gains of approximately $3.7 million for the year ended December 31, 2012, compared to approximately $9.5 million of net gains recorded for the year ended December 31, 2011, representing a total decrease of approximately $5.8 million in segment gross margin associated with derivative instruments.

Operating and maintenance costs of our Gathering, Processing and Transportation segment were $40.5 million higher for the year ended December 31, 2012 when compared to the year ended December 31, 2011, primarily due to the following:

- Increased workforce related costs of approximately $8.4 million associated with the full year operation of the Allison processing plant in 2012, in addition to costs incurred to enhance and maintain the safety and operational efficiency of our systems;
- Increased costs of $12.9 million, of which approximately $8.2 million related to additional maintenance and supplies and $2.7 million related to additional property taxes primarily resulting from the additional assets we placed into service during late 2011;
- Increased pipeline integrity costs of $6.1 million we incurred to ensure the ongoing safe and reliable operation of our existing plants, pipelines and related facilities; and
- $4.3 million of costs we expensed related to a development project on our East Texas system that we do not expect to complete until production levels reach a sustainable level to support our expansion activities in the region.

General and administrative costs of our Gathering, Processing and Transportation segment increased approximately $14.2 million for the year ended December 31, 2012 as compared with the year ended December 31, 2011, primarily due to the additional costs we are allocated for the services we share with other affiliates including, but not limited to, director and executive oversight, treasury, cash management, risk management, accounting, information technology and commercial services and the associated benefits and costs for the personnel that provide these services. The costs we are allocated for these services increase with the size and scope of our operating activities. Our allocated costs increased for the year ended December 31, 2012 compared with the year ended December 31, 2011 due to rising benefit costs, including higher pension expense due to lower discount rates, and an increased number of support service employees.

Depreciation and amortization expense of our Gathering, Processing and Transportation segment for the year ended December 31, 2012 was $7.2 million lower than depreciation expense for the year ended December 31, 2011. Effective July 1, 2011, we revised the depreciation rates for our gathering, processing and transportation business following the completion of a study to reassess the expected useful lives our property, plant and equipment, which resulted in a $17.0 million decrease in depreciation expense for the year ended December 31, 2012 as compared with the year ended December 31, 2011. The reduced rate of depreciation expense for 2012 was partially offset by additional depreciation associated with assets we placed in service in late 2011 and during 2012.

Future Prospects for Gathering, Processing and Transportation

We have completed and are currently pursuing several expansion projects that are designed to increase natural gas processing, NGL production and natural gas and NGL transportation capacity. The following table and discussion summarizes our projects, which we have recently placed into service or expect to place into service in future periods. After the Offering, the projects below are now funded by the Partnership and EEP based on their proportionate ownership percentages in Midcoast Operating.

Project	Estimated Capital Costs	In-service Date	Funding
	(in millions)		
Ajax Cryogenic Processing Plant	$230	Q3 2013	EEP
Texas Express NGL system	$400	Q4 2013	Joint(2)
Beckville Cryogenic Processing Plant	$145	Early 2015	Joint(1)

(1) Following the Offering in November 2013, Beckville is now funded by EEP and MEP based on their proportionate ownership percentages in Midcoast Operating, which is currently 61% and 39%, respectively.

(2) We own a 35% joint venture interest in the Texas Express NGL system. Estimated capital costs represent 35% of the total projected costs associated with constructing both the mainline and the gathering system.

Ajax Cryogenic Processing Plant

We expect development of the Granite Wash play in the Texas Panhandle and western Oklahoma to continue due to the prolific nature of the wells, current market prices for NGLs and crude oil and the application of horizontal drilling and fracturing technology to the formation. In order to accommodate the expected natural gas production growth from the Granite Wash play, we began commissioning the operations of a cryogenic processing plant and related facilities in the third quarter of 2013, which we refer to as our Ajax processing plant. The Ajax processing plant, condensate stabilizer, field and plant compression, gathering infrastructure and NGL pipelines provide necessary capacity to accommodate the anticipated volume growth within our Anadarko system. The total cost of constructing the Ajax processing plant and related facilities was approximately $230 million. The Ajax processing plant increases the total processing capacity of our Anadarko system by approximately 150 million cubic feet per day, or MMcf/d, to approximately 1,150 MMcf/d and also increases the system's condensate stabilization capacity by approximately 2,000 Bpd. The Ajax processing plant is capable of producing approximately 15,000 barrels per day, or Bpd, of NGLs now that the Texas Express NGL pipeline, which we refer to as the mainline, was completed and put into operation during the fourth quarter of 2013 as discussed below.

Texas Express NGL System

On October 31, 2013, we, Enterprise Product Partners L.P., or Enterprise, Anadarko Petroleum Corporation, or Anadarko, and DCP Midstream Partners, LP, or DCP Midstream, announced the start of service on the Texas Express NGL system, which consists of two separate joint ventures with third parties to design and construct a new NGL pipeline, or mainline, and NGL gathering system. The joint venture ownership of the mainline portion of the Texas Express NGL system is owned 35% by Enterprise, 35% by us, 20% by Anadarko and 10% by DCP Midstream. The joint venture ownership of the new NGL gathering system is owned 45% by Enterprise, 35% by us and 20% by Anadarko. Enterprise constructed and serves as the operator of the mainline, while we constructed and operate the new gathering system.

The Texas Express NGL pipeline originates near Skellytown, Texas in the Texas Panhandle and extends approximately 580-miles to NGL fractionation and storage facilities in the Mont Belvieu area on the Texas Gulf Coast. The mainline has an initial capacity of approximately 280,000 Bpd and is expandable to approximately 400,000 Bpd with additional pump stations on the system. There are currently capacity reservations on the mainline that, when fully phased in, will total approximately 250,000 Bpd. The new NGL gathering system initially consists of approximately 116-miles of gathering lines that connect the mainline to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma and to Barnett Shale processing plants in North Texas. The gathering system is currently expected to include 270-miles of gathering lines by 2019. Volumes from the Rockies, Permian Basin and Mid-Continent regions will be delivered to the Texas Express NGL system utilizing Enterprise's existing Mid-America Pipeline assets between the Conway hub and Enterprise's Hobbs NGL fractionation facility in Gaines County, Texas. In addition, volumes from and to the Denver-Julesburg Basin in Weld County, Colorado are able to access the Texas Express NGL system through the connecting Front Range Pipeline which is being constructed by Enterprise, DCP Midstream and Anadarko.

We expect that the Texas Express NGL system will serve as a link between growing supply sources of NGLs in the Anadarko and Permian basins and the Mid-Continent and Rockies regions of the United States and the primary demand markets on the U.S. Gulf Coast. We expect our total contributions to be approximately $400 million for the construction of the Texas Express NGL system.

Beckville Cryogenic Processing Plant

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville processing plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation, which is comprised of approximately ten counties in East Texas and has been a steady producer of natural gas for decades. Production from this play typically contains two to three gallons of NGLs per Mcf of natural gas. The region currently produces approximately 2.2 billion cubic feet per day, or Bcf/d, of natural gas with 73,000 Bpd of associated NGLs. Until recently, the primary exploitation method in the Cotton Valley formation has been vertical wells. Lower horizontal drilling costs, coupled with the latest fracturing technology, has brought significant interest back to this area. Economics associated with horizontal wells in the Cotton Valley formation compare favorably to other rich natural gas plays, which has encouraged producers to increase drilling activity in the region. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. In the third quarter of 2013, we initiated construction activities at our Beckville processing plant and the related facilities on our East Texas system. We estimate the cost of constructing the plant to be approximately $145 million and expect it to commence service in early 2015.

Logistics and Marketing

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business, thereby enhancing our competitive position. In addition, our logistics and marketing services provide our customers with the opportunity to receive enhanced economics by providing access to premium markets through the transportation capacity and other assets we control. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from pipeline systems and processing plants and sells and delivers them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants.

The physical assets of our logistics and marketing business primarily consist of:

- Approximately 250 transport trucks, 300 trailers and 205 railcars for transporting NGLs;
- Our TexPan liquids railcar facility near Pampa, Texas;
- An approximately 40-mile crude oil pipeline and associated crude oil storage facility near Mayersville, Mississippi, including a crude oil barge loading facility located on the Mississippi River; and
- An approximately 30-mile propylene pipeline extending from Exxon’s refinery in Chalmette, Louisiana to an interconnecting Chevron pipeline near Lafitte, Louisiana.

We also enter into agreements with various third parties to obtain natural gas and NGL supply, transportation, gas balancing, fractionation and storage capacity in support of the logistics and marketing services we provide to our gathering, processing and transportation business and to third-party customers. These agreements provide our logistics and marketing business with the following:

- up to approximately 79,000 Bpd of firm NGL fractionation capacity;
- approximately 2.5 Bcf of firm natural gas storage capacity;
- up to approximately 120,000 Bpd of firm NGL transportation capacity on the Texas Express NGL system;
- up to approximately 89,000 Bpd of additional NGL transportation capacity, a significant portion of which is firm capacity, through transportation and exchange agreements with four NGL pipeline transportation companies; and
- approximately 5.0 MMBbls of firm NGL storage capacity.

The following table sets forth the operating results of our logistics and marketing business for the years ended December 31, 2013, 2012, and 2011:

	December 31,		
	2013	2012	2011
		(in millions)	
Operating revenues	$4,864.6	$4,539.9	$6,914.0
Cost of natural gas and natural gas liquids	4,779.5	4,452.9	6,795.5
Segment gross margin	85.1	87.0	118.5
Operating and maintenance	71.4	80.8	76.8
General and administrative	11.6	19.1	10.1
Depreciation and amortization	7.2	7.0	7.5
Operating expenses	90.2	106.9	94.4
Operating income (loss)	$ (5.1)	$ (19.9)	$ 24.1

Our logistics and marketing business derives a majority of its segment gross margin, which we define as revenue generated from the sale of natural gas, NGLs and condensate less the cost of natural gas and natural gas liquids purchased, from purchasing and receiving natural gas, NGLs and other products from our gathering, processing and transportation business and from third-party pipeline systems and processing plants and selling and delivering them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants. We contract for third-party pipeline capacity under firm and interruptible transportation contracts for which the pipeline capacity depends on volumes of natural gas from our natural gas assets, which provides us with access to several third-party interstate and intrastate pipelines that can be used to transport natural gas and NGLs to primary market hubs where they can be sold to major customers for these products. Our logistics and marketing business also uses owned and leased trucks and specialized trailers and railcars to transport products such as NGLs, condensate and other liquid hydrocarbons to market. In some instances, our margin per unit of volume sold can be higher if the commodity being marketed requires specialized handling, treating, stabilization or other services.

Our logistics and marketing business also derives segment gross margin from the relative difference in natural gas and NGL prices between the contracted index at which the natural gas and NGLs are purchased and the index price at which they are sold, otherwise known as the “basis spread,” which can vary over time or by location, as well as due to local supply and demand factors. Natural gas and NGLs purchased and sold by our logistics and marketing business is primarily priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. We enter into long-term, fixed-price purchase or sales contracts with our customers and generally will enter into offsetting hedge positions under the same or similar terms.

Year ended December 31, 2013 compared with year ended December 31, 2012

The operating income of our Logistics and Marketing segment for the year ended December 31, 2013 increased $14.8 million, as compared with the same period in 2012. Segment gross margin decreased $1.9 million for the year ended December 31, 2013, as compared with the year ended December 31, 2012.

Segment gross margin experienced non-cash, mark-to-market net losses of $7.1 million from December 31, 2012 to December 31, 2013 mostly due to changes in the average forward prices of natural gas, NGLs and condensate. The average forward and daily prices for natural gas and propane increased for the year ended December 31, 2013, compared to the year ended December 31, 2012. We use the non-qualifying commodity derivatives to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our logistics and marketing business.

Segment gross margin was also negatively impacted by modestly lower storage margins resulting from the sale of liquids product inventory at prevailing market prices relative to the cost of the product inventory in storage. Contributing to segment gross margin was the expiration of certain transportation fees for natural gas being transported on a third party pipeline. These fees expired, effective June 30, 2012, and reduced natural gas expense by approximately $2.0 million for the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Segment gross margin for the current year was also affected by only $3.4 million of non-cash charges to inventory for the year ended December 31, 2013, as compared with $9.8 million loss for the year ended December 31, 2012, which we recorded to reduce the cost basis of our natural gas inventory to net realizable value. Since we hedge our storage positions financially, these charges are recovered when the physical natural gas inventory is sold or the financial hedges are realized.

Operating and maintenance costs of our Logistics and Marketing segment were $9.4 million lower for the year ended December 31, 2013 compared with the year ended December 31, 2012, due to reduced outside contract labor costs and lower maintenance activities on existing trucks and trailers resulting from a more updated fleet.

General and administrative costs of our Logistics and Marketing segment decreased $7.5 million for the year ended December 31, 2013, compared to the year ended December 31, 2012, due to costs we incurred in 2012 for the investigation of accounting irregularities at our trucking and NGL marketing subsidiary.

Depreciation and amortization expense was relatively flat for the year ended December 31, 2013 when compared with the year ended December 31, 2012.

Year ended December 31, 2012 compared with year ended December 31, 2011

The segment gross margin of our logistics and marketing business was $31.5 million lower for the year ended December 31, 2012 compared with the year ended December 31, 2011, due to fewer opportunities to benefit from price differentials between market centers as a result of lower natural gas and NGL prices during 2012. Also contributing to the lower segment gross margin was the centralization of our marketing function to our corporate offices in Houston, Texas. We scaled back our logistics and marketing activities during this period to facilitate the orderly transition of these activities, and we began to gradually increase our logistics and marketing activities to previous levels during the fourth quarter of 2012.

Partially offsetting the decrease in segment gross margin was $11.7 million of segment gross margin realized from access to additional condensate stabilization facilities that our gathering, processing and transportation business placed into service during 2011, in addition to other assets we placed into service during 2012 to enable delivery of crude oil to barges from our crude oil pipeline, storage facility and barge loading facility near Mayersville, Mississippi.

Our logistics and marketing business was negatively affected by non-cash, mark-to-market net losses of $2.5 million for the year ended December 31, 2012, compared to $7.0 million of net gains recorded for the year ended December 31, 2011, representing a total decrease of $9.5 million in segment gross margin associated with derivative instruments.

Operating and maintenance costs of our logistics and marketing business were $4.0 million higher for the year ended December 31, 2012 when compared with the year ended December 31, 2011, primarily due to additional assets placed into service during 2012 associated with the acquisition of our liquids rail loading facilities and integrity and environmental costs associated with our crude oil pipeline in Mississippi.

General and administrative costs of our logistics and marketing business were $9.0 million higher for the year ended December 31, 2012 when compared with the year ended December 31, 2011, primarily due to costs we incurred in 2012 for the investigation of accounting irregularities at our trucking and NGL marketing subsidiary.

Depreciation and amortization expense for the year ended December 31, 2012 was slightly lower than depreciation and amortization expense for the year ended December 31, 2011.

Corporate Activities

Our corporate activities consist of interest expense, interest income and other costs such as income taxes, which are not allocated to our business segments.

	December 31,		
	2013	2012	2011
		(in millions)	
General and administrative	—	0.2	0.1
Operating expenses	—	0.2	0.1
Operating loss		(0.2)	(0.1)
Other income (expense)	0.3	(0.1)	2.8
Interest expense	1.7	—	—
Income tax expense	8.3	3.8	2.9
Net income attributable to: Noncontrolling interest	(0.6)	—	—
Net loss attributable to general and limited partners	$(9.1)	$(4.1)	$(0.2)

Year ended December 31, 2013 compared with year ended December 31, 2012

Our interest cost for the year-ended December 31, 2013 and 2012 is comprised of the following:

	December 31,	
	2013	2012
	(in millions)	
Interest cost incurred	$20.2	$11.9
Interest capitalized	18.5	11.9
Interest expense	$ 1.7	$ —
Interest cost paid	$20.2	$11.9
Weighted average interest rate[1]	2.5%	—

[1] At December 31, 2012, MEP had no outstanding debt and no weighted average interest rate.

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income are typically borne by our unitholders through the allocation of taxable income.

The tax structure that exists in Texas imposes taxes that are based upon many, but not all, items included in net income. Our income tax expense of $8.3 million for the year ended December 31, 2013, is computed by applying a 0.5% Texas state income tax rate to modified gross margin, as defined by Texas state income tax laws, and $6.0 million for the change in Texas tax law as discussed in Note 15. *Income Taxes*. For 2012, we had an income tax expense of $3.8 million, which we computed by applying a 0.5% Texas state income tax rate to modified gross margin.

Year ended December 31, 2012 compared with year ended December 31, 2011

The net loss we experienced in 2012 from corporate activities was mostly attributable to the income taxes allocated to us by EEP with respect to our activities. In addition, during 2011 we recognized other income resulting from gain on the sale of a carbon dioxide plant and income derived from the favorable settlement of a lawsuit.

For the year ended December 31, 2012, we capitalized $11.9 million to our construction projects compared with $3.3 million for the year ended December 31, 2011. The following table sets forth our interest cost for the years ended 2012 and 2011 is detailed below:

	December 31,	
	2012	2011
	(in millions)	
Interest cost incurred	$11.9	$ 3.3
Interest capitalized	11.9	3.3
Interest expense	$ —	$ —
Interest cost paid	$11.9	$ 3.3
Weighted average interest rate[1]	—	—

[1] At December 31, 2012 and 2011, MEP had no debt and no weighted average interest rate, respectively.

Our income tax expense was $3.8 million for the year ended 2012 compared to $2.9 million for the year ended 2011.

LIQUIDITY AND CAPITAL RESOURCES

Historically, our sources of liquidity included cash generated from operations and funding from EEP. We were dependent upon EEP and its affiliates for our treasury services. We now have separate bank accounts from EEP, but EEP provides treasury services on our General Partner's behalf under an intercorporate services agreement that we entered into with EEP at the closing of the Offering. Under the intercorporate services agreement, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would be fully allocable to Midcoast Operating by $25.0 million annually following the closing of the Offering. In addition, at the close of the Offering, Midcoast Operating entered into a Financial Support Agreement (the "Financial Support Agreement"), between Midcoast Operating and EEP, pursuant to which EEP will, from time to time, provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party.

We expect our ongoing sources of liquidity to include cash generated from operations of Midcoast Operating, borrowings under Midcoast Operating's working capital credit facility, borrowings under our revolving credit facility and issuances of additional debt and equity securities. We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements and long-term capital expenditure requirements and to make quarterly cash distributions to our unitholders.

Credit Facility

On November 13, 2013, in connection with the closing of the Offering, the Partnership, Midcoast Operating, and their material domestic subsidiaries, entered into a Credit Agreement, which we refer to as the Credit Agreement, by and among the Partnership, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, the material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially (1) $90.0 million under the letter of credit facility and (2) $75.0 million under the swing line facility. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility matures in three years, subject to four one-year requests for extensions. At December 31, 2013, we were in compliance with the terms of our financial covenants.

Loans under the Credit Agreement accrue interest at a per annum rate by reference, at the borrowers' election, to the Eurodollar rate, which is equal to the LIBOR rate or a comparable or successor rate reasonably approved by the Administrative Agent, or base rate, in each case, plus an applicable margin. The applicable margin on Eurodollar (LIBOR) rate loans ranges from 1.75% to 2.75% and the applicable margin on base rate loans ranges from 0.75% to 1.75%, in each case determined based upon our total leverage ratio (as defined below) at the applicable time. A letter of credit fee is payable by the borrowers' equal to the applicable margin for Eurodollar (LIBOR) rate loans times the daily amount available to be drawn under outstanding letters of credit. A commitment fee is payable by us equal to an applicable margin times the daily unused amount of the lenders' commitment, which applicable margin ranges from 0.30% to 0.50% based upon our total leverage ratio at the applicable time.

Each of our domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The Credit Agreement is unsecured but security will be provided upon occurrence of any of the following: (1) for two consecutive quarters, the Total Leverage Ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (2) uncured breach to certain terms and conditions of the Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

Additionally, the Credit Agreement contains various covenants and restrictive provisions which limit the ability of the Partnership, Midcoast Operating and their subsidiaries to incur certain liens or permit them to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests during the continuance of a default, incur or guarantee additional debt, repay subordinated debt prior to maturity, make certain investments and acquisitions, alter their lines of business, enter into certain types of transactions with affiliates and enter into agreements that restrict their ability to perform certain obligations under the Credit Agreement or to make payments to a borrower or any of their material subsidiaries.

The Credit Agreement also requires compliance with two financial covenants. The Partnership must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio) of the Partnership and its consolidated subsidiaries (including Midcoast Operating), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. The Partnership also must maintain (on a consolidated basis), as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00.

These covenants are subject to exceptions and qualifications set forth in the Credit Agreement. At such time as the Partnership obtains an investment grade rating from either Moody's or S&P, certain covenants under the Credit Agreement will no longer be applicable to either the borrowers or the guarantors, or in some instances, any of them (including, but not limited to, the obligation to provide security in certain circumstances, certain restrictions on liens, investments and debt, and restrictions on dispositions).

The Credit Agreement also contains customary representations, warranties, indemnities and remedies provisions. In addition, the Credit Agreement contains events of default customary for transactions of this nature, including (1) the failure of either borrower to make payments required under the Credit Agreement; (2) the failure to comply with covenants and financial ratios in the Credit Agreement; (3) the occurrence of a change of control; (4) the institution of insolvency or similar proceedings against either borrower, a guarantor or a material subsidiary; and (5) the occurrence of a payment default, or the acceleration of payment, based on a non-payment default, under any other material indebtedness of either borrower or any of their subsidiaries. During the existence of an event of default, subject to the terms and conditions of the Credit Agreement, the lenders may terminate all outstanding commitments under the Credit Agreement and may declare any outstanding principal, together with accrued and unpaid interest, to be immediately due and payable and may require that all outstanding letters of credit be collateralized by cash.

Under the Credit Agreement, a change of control will be triggered if EEP or Enbridge ceases to control, directly or indirectly, our General Partner or if the general partner of Midcoast Operating ceases to be wholly owned, directly or indirectly, by the Partnership.

The amounts we may borrow under the terms of our Credit Agreement are reduced by the face amount of our letters of credit outstanding. At December 31, 2013, we could borrow $515.0 million under the terms of our Credit Agreement, determined as follows:

	(in millions)
Total credit available under Credit Agreement	$850.0
Less: Amounts outstanding under Credit Agreement	335.0
Total amount we could borrow at December 31, 2013	$515.0
Weighted average interest rate	2.5%

Working Capital Credit Facility

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a $250.0 million working capital credit facility with EEP as the lender. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility are scheduled to mature on November 13, 2017 and accrue interest at a per annum rate of the London Interbank Offered Rate, or LIBOR, plus 2.5%. EEP's commitment to lend pursuant to the working capital credit facility will end on the earlier of the facility's maturity date (by acceleration or otherwise) and the date on which EEP owns less than 20% of the outstanding limited partner interests in Midcoast Operating. If EEP's commitment to lend has terminated before the facility has matured (by acceleration or otherwise), then the aggregate amount of all outstanding borrowings under the facility will automatically convert to a term loan that will bear interest at LIBOR (calculated as of the conversion date) plus 2.5%. Midcoast Operating has agreed to pay a commitment fee on the unused commitment at a per annum rate of 0.4250%, payable each fiscal quarter.

The working capital credit facility contains customary events of default, including (1) the failure of Midcoast Operating to make payments required under the working capital credit facility or comply with the conditions of such working capital credit facility; (2) the failure of any of the representations or warranties of Midcoast Operating to be true in all material respects when made; (3) the occurrence of a change of control; (4) the institution of insolvency or similar proceedings against Midcoast Operating or us; and (5) the occurrence of a default under any other material indebtedness of Midcoast Operating or us. During the existence of an event of default, subject to the terms and conditions of the working capital credit facility, EEP may terminate its commitment and may declare any outstanding principal, together with accrued and unpaid interest, to be immediately due and payable. The working capital credit facility also contains certain customary representations, warranties, indemnities and remedies provisions and also provides that, if the Credit Agreement is secured, the working capital credit facility also will be secured to the same extent on a second lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the working capital credit facility and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Financial Support Agreement

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP has agreed to provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party. Under the Financial Support Agreement, EEP's support of Midcoast Operating's and its wholly owned subsidiaries' obligations will terminate on the earlier to occur of (1) the fourth anniversary of the closing of the Offering and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in the Partnership), less than 20% of the total outstanding limited partner interest in Midcoast Operating.

The annual costs that Midcoast Operating initially estimates that it will incur under the Financial Support Agreement range from approximately $4.0 million to $5.0 million and are based on the cumulative average amount of letters of credit and guarantees that EEP will provide on Midcoast Operating's and its wholly owned subsidiaries' behalf multiplied by a 2.5% annual fee. The cumulative average amount of letters of credit and guarantees will be calculated (1) with respect to letters of credit, by reference to the aggregate face value, in U.S. dollars, of letters of credit outstanding at the close of business on any business day, after taking into account any changes in such amount since the close of business on the immediately preceding business day, and (2) with respect to guarantees, by reference to the net realizable financial obligation of Midcoast Operating and its wholly owned subsidiaries under the applicable contracts, in each case after taking into account market fluctuations in commodity prices, any related EEP letters of credit and any increases or decreases underlying each guarantee. The "net realizable financial obligation" is (1) in the case of outstanding commodity derivative contracts, the amount required to terminate or discharge each such contract based upon current market prices of the relevant commodity and (2) in the case of natural gas and NGL purchase agreements, the outstanding amount owed for product received that would be recorded as a liability under U.S. GAAP, in each case, net of any amounts owed to Midcoast Operating under any agreements with counterparties that have received guarantees from EEP. Based on the Partnership's 39% controlling interest in Midcoast Operating, the Partnership initially estimates that its proportionate share of these annual costs will range from $1.6 million to $2.0 million.

The Financial Support Agreement also provides that if the Credit Agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the Financial Support Agreement and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Available Liquidity

Our primary sources of liquidity are provided by the Credit Agreement and our working capital facility. As set forth in the following table, we had approximately $769.9 million of liquidity available to us at December 31, 2013 to meet our ongoing operational, investment and financing needs.

	(in millions)
Cash and cash equivalents	$ 4.9
Total credit available under Credit Agreement	850.0
Total credit available under Working Capital Credit Facility	250.0
Less: Amounts outstanding under Credit Agreement	335.0
Total	$769.9

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013 and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. The Receivables Agreement and the transactions contemplated thereby were approved by a special committee of the board of directors of Enbridge Management, which prior to the Offering, effectively managed the business of the Predecessor through its management of EEP's business. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of those of ours subsidiaries and other subsidiaries of EEP that are parties thereto up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement. EEP and the Partnership each act in an administrative capacity as collection agent on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. Prior to the amendment to the Receivables Agreement on December 2, 2013 EEP was the sole collection agent on behalf of the Enbridge subsidiary. EEP and the Partnership have no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative—affiliate" expense in our consolidated statements of income. For the year ended December 31, 2013, the loss stemming from the discount on the receivables sold was not material. For the year ended December 31, 2013, we derecognized and sold $1,566.7 million, of accrued receivables to the Enbridge subsidiary. For the year ended December 31, 2013, the cash proceeds were $1,566.3 million, which was remitted to EEP or the Partnership, as applicable, in their capacity as collection agent, through our centralized treasury system. As of December 31, 2013, $273.6 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

Cash Requirements

Capital Spending

In 2014, we expect to spend approximately $150.0 million on system enhancements and other projects associated with our natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. We made expenditures of $554.8 million for the year ended December 31, 2013, inclusive of $188.6 million in contributions to the Texas Express Pipeline. At December 31, 2013, we had approximately $120.7 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2014.

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under the Credit Facility and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

In addition, EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time. These acquisitions, sometimes referred to as "drop-down" transactions, will provide an alternative source of funding for EEP while at the same time providing an opportunity for meaningful growth in our cash flows. However, EEP is under no obligation to offer to sell us additional interests in Midcoast Operating, and we are under no obligation to buy any such additional interests. As a result, we do not know when or if any such additional interests will be offered to us to purchase. We believe that we will be well-positioned to acquire additional interests in Midcoast Operating if the opportunity arises.

Under the amended and restated agreement of limited partnership of Midcoast Operating that we and EEP entered into in November 2013, we and EEP each have the option to contribute our proportionate share of additional capital to Midcoast Operating if any additional capital contributions are necessary to fund expansion capital expenditures or other growth projects. To the extent that we or EEP elect not to make any such capital contributions, the contributing party will be permitted to make additional capital contributions to Midcoast Operating to the extent necessary to fully fund such expenditures in exchange for additional ownership interests in Midcoast Operating.

Forecasted Expenditures

We categorize our capital expenditures as either maintenance or expansion capital expenditures. Maintenance capital expenditures are cash expenditures that are made to maintain our asset base, operating capacity or operating income or to maintain the existing useful life of any of our capital assets, in each case over the long term. Examples of maintenance capital expenditures include expenditures to replace pipelines or processing facilities, to maintain equipment reliability, integrity and safety or to comply with existing governmental regulations and industry standards. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as maintenance capital expenditures. We expect to incur continuing annual maintenance capital expenditures primarily for well-connects and for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital expenditures will increase due to the growth of our pipeline systems. We expect to fund our proportional share of maintenance capital expenditures through operating cash flows.

Expansion capital expenditures are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our asset base, operating capacity or operating income over the long term or meaningfully extend the useful life of any of our capital assets. Examples of expansion capital expenditures include the acquisition of additional assets or businesses, as well as capital projects that improve the service capability of our existing assets, increase operating capacities or revenues, reduce operating costs from existing levels or enable us to comply with new governmental regulations or industry standards. We anticipate funding our proportional share of expansion capital expenditures temporarily through borrowings under our revolving credit facility, with long-term debt and equity funding being obtained when needed and as market conditions allow.

If EEP elects not to fund any capital expenditures at Midcoast Operating, we will have the option to fund all or a portion of EEP's proportionate share of such capital expenditures in exchange for additional interests in Midcoast Operating. As a result, if our interests in Midcoast Operating increase, our proportionate share of the capital expenditures incurred by Midcoast Operating will also increase proportionate to our interest in Midcoast Operating. To the extent that EEP elects not to fund all or a portion of its proportionate share of Midcoast Operating's capital expenditures, and we elect not to fund any capital expenditures not funded by EEP, we expect that Midcoast Operating will not pursue the applicable capital projects associated with such unfunded capital expenditures.

The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and core maintenance for the year ending December 31, 2014. Although we anticipate making these expenditures in 2014, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. We made capital expenditures of $554.8 million, including $60.2 million on core maintenance activities, for the year ended December 31, 2013. For the full year ending December 31, 2014, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures (in millions)
Capital Projects	
Beckville Cryogenic Processing Plant	$110
Wellconnect Expansion Capital	50
Texas Express NGL system	20
Expansion Capital[1]	140
Maintenance Capital Expenditure Activities	65
Less joint funding from:	
EEP[2]	235
	$150

(1) Other enhancements include new compression, growth opportunities as well as other enhancements.
(2) Joint funding is based upon EEP's current 61% ownership of Midcoast Operating.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at December 31, 2013 for each of the indicated calendar years:

	Notional	2014	2015	2016	2017	2018	Total[3]
			(in millions)				
Swaps							
Natural gas[1]	42,475,861	$ (0.4)	$ 0.1	$—	$ —	$ —	$(0.3)
NGL[2]	3,856,300	(7.7)	0.4	—	—	—	(7.3)
Crude Oil[2]	1,463,100	(5.1)	1.7	0.7	—	—	(2.7)
Options							
Natural gas—puts purchased[1]	5,840,000	0.2	1.7	—	—	—	1.9
Natural gas—calls written[1]	1,277,500	—	(0.3)	—	—	—	(0.3)
NGL—puts purchased[2]	1,424,250	2.9	6.0	—	—	—	8.9
NGL—calls written[2]	383,250	(1.0)	(1.0)	—	—	—	(2.0)
Crude Oil—puts purchased[2]	273,750	—	1.8	—	—	—	1.8
Crude Oil—calls written[2]	273,750	—	(1.9)	—	—	—	(1.9)
Forward contracts							
Natural gas[1]	50,863,677	0.5	0.4	0.1	—	—	1.0
NGL[2]	11,756,601	(0.1)	—	—	—	—	(0.1)
Crude Oil[2]	1,214,323	(0.5)	—	—	—	—	(0.5)
Totals		$(11.2)	$ 8.9	$ 0.8	$ —	$ —	$(1.5)

(1) Notional amounts for natural gas are recorded in millions of British thermal units, or MMBtu.

(2) Notional amounts for NGL and crude oil are recorded in Barrels, or Bbl.

(3) Fair values exclude credit adjustments of approximately $0.1 million of gains at December 31, 2013.

Distributions

Our partnership agreement requires that we distribute all of our available cash quarterly. This requirement forms the basis of our cash distribution policy and reflects a basic judgment that our unitholders will be better served by distributing our available cash rather than retaining it, because, among other reasons, we believe we will generally finance any expansion capital expenditures from external financing sources. Under our current cash distribution policy, we intend to make a minimum quarterly distribution to the holders of our Class A common units and subordinated units of $0.3125 per unit, or $1.25 per unit on an annualized basis, to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including the payment of expenses to our General Partner and its affiliates. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions in this or any other amount, and our General Partner has considerable discretion to determine the amount of our available cash each quarter. In addition, our General Partner may change our cash distribution policy at any time, subject to the requirement in our partnership agreement to distribute all of our available cash quarterly. Generally, our available cash is our (1) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (2) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we expect to have more cash to distribute than would be the case if we were subject to federal income tax. If we do not generate sufficient available cash from our operations, we may, but are under no obligation to, borrow funds to pay the minimum quarterly distribution to our unitholders.

Our partnership agreement provides that, during the subordination period, the Class A common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.3125 per Class A common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the Class A common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the Class A common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution on the Class A common units from prior quarters. Furthermore, no arrearages will accrue or be payable on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that, during the subordination period, there will be available cash to be distributed on the Class A common units.

The subordination period began upon the closing of our initial public offering and will extend until the first business day following the distribution of available cash in respect of any quarter beginning after December 31, 2016 that each of the following tests are met:

- Distributions of available cash from operating surplus on each of the outstanding Class A common units, subordinated units and general partner units equaled or exceeded $1.25 (the annualized minimum quarterly distribution), for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- The adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of $1.25 (the annualized minimum quarterly distribution) on all of the outstanding Class A common units, subordinated units and general partner units during those periods on a fully diluted basis; and
- There are no arrearages in payment of the minimum quarterly distribution on the Class A common units.

Notwithstanding the foregoing, the subordination period will automatically terminate on the first business day following the distribution of available cash in respect of any quarter, beginning with the quarter ending December 31, 2014, that each of the following tests are met:

- Distributions of available cash from operating surplus on each of the outstanding Class A common units, subordinated units and general partner units equaled or exceeded $1.875 (150% of the annualized minimum quarterly distribution), plus the related distributions on the incentive distribution rights, for the four-quarter period immediately preceding that date;
- The adjusted operating surplus generated during the four-quarter period immediately preceding that date equaled or exceeded the sum of (1) $1.875 (150% of the annualized minimum quarterly distribution) on all of the outstanding Class A common units, subordinated units and general partner units during that period on a fully diluted basis and (2) the corresponding distributions on the incentive distribution rights; and
- There are no arrearages in payment of the minimum quarterly distributions on the Class A common units.

When the subordination period ends, the outstanding subordinated units will convert into Class B common units, and all Class A common units will no longer be entitled to arrearages. The Class B common units will be convertible at the option of the holder into Class A common units at any time that our General Partner determines, based on the advice of counsel, that the Class B common units to be converted have like intrinsic economic and federal income tax characteristics to Class A common units.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2013:

	2014	2015	2016	2017	2018	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$120.7	$ —	$ —	$ —	$ —	$ —	$ 120.7
Other operating leases	24.6	24.3	23.7	22.7	15.5	91.1	201.9
Right-of-way[2]	0.6	0.3	0.4	0.1	0.1	2.2	3.7
Product purchase obligations[3]	24.5	17.7	8.8	15.7	26.1	147.1	239.9
Transportation/Service contract obligations[4]	46.0	46.7	44.9	88.8	99.1	513.2	838.7
Fractionation agreement obligations[5]	63.3	63.3	63.3	63.3	63.3	276.6	593.1
Total	$279.7	$152.3	$141.1	$190.6	$204.1	$1,030.2	$1,998.0

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our growth projects.

(2) Right-of-way payments are estimated to approximate $0.1 million to $0.6 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2018.

(3) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at prices approximating market at the time of delivery.

(4) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

(5) The fractionation agreement obligations represent the minimum payment amounts for firm fractionation of our NGL supply that we reserve at third party fractionation facilities.

The payments made under our obligations and commitments for the years ended December 31, 2013, 2012 and 2011 were $334.4 million, $117.0 million and $98.4 million, respectively.

Cash Flow Analysis

The following table summarizes the changes in cash flows by operating, investing and financing for each of the years indicated:

	For the year ended December 31, 2013	For the year ended December 31, 2012	Variance 2013 vs. 2012 Increase (Decrease)
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 420.9	$ 352.7	$ 68.2
Investing activities	(522.3)	(614.5)	92.2
Financing activities	106.3	261.8	(155.5)
Net increase in cash and cash equivalents	4.9	—	4.9
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of period	$ 4.9	$ —	$ 4.9

Operating Activities

Net cash provided by our operating activities increased $68.2 million for the twelve month period ended December 31, 2013 compared to the year ended December 31, 2012, primarily due to an increase in our working capital accounts of $171.1 million. This increase due to our working capital accounts was partially offset by a $113.6 million decrease in net income, offset by other non-cash items.

Changes in our working capital accounts are shown in the following table and discussed below:

	For the year ended December 31, 2013	2012	Variance 2013 vs. 2012
		(in millions)	
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 7.9	$ 67.8	$ (59.9)
Due from General Partner and affiliates	(633.9)	4.5	(638.4)
Accrued receivables	295.6	(68.2)	363.8
Inventory	(12.2)	12.0	(24.2)
Current and long-term other assets	(14.3)	(4.5)	(9.8)
Due to General Partner and affiliates	522.8	17.9	504.9
Accounts payable and other	34.6	2.1	32.5
Accrued purchases	4.9	6.4	(1.5)
Interest payable	0.3	—	0.3
Property and other taxes payable	3.4	—	3.4
Net change in working capital accounts	$ 209.1	$ 38.0	$ 171.1

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the year ended December 31, 2013, compared with the year ended December 31, 2012, is primarily the result of general timing differences for cash receipts and payments associated with our current and related party accounts. Other items affecting our cash flows from operating assets and liabilities include the following:

- The change in accrued receivables was favorable due to the sale of $335.9 million to a subsidiary of Enbridge pursuant to the Receivables Agreement. Similar sales of accrued receives did not occur in 2012, since 2013 is the first year the Receivables Agreement was active. For more information, refer to the discussion above *Sale of Accounts Receivable;*
- The changes in the balances of due to and due from General Partner and affiliates are primarily attributable to transition of cash management functions from EEP to MEP following the Offering. EEP provided us with interim cash management services following the Offering to facilitate the collection of and payment on our accounts, which resulted in increase in amounts receivable from and payable to EEP; and
- The change in trade receivables was unfavorable due to unfavorable pricing spreads of $57.0 million between hubs at Conway and Mount Belvieu. In 2012, we had the opportunity to benefit from purchasing natural gas at Conway and selling it at a higher price at Mount Belvieu. In 2013, the price differential reversed, thus we did not purchase and sell as much natural gas between these two hubs.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2013 increased by $92.2 million, compared to the year ended December 31, 2012, primarily due to:

- Increased restricted cash balance of $61.5 million consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary in accordance with the Receivables Agreement. For more information, refer to Item 7. *Liquidity and Capital Resources-Sale of Accounts Receivable*; and
- Increased contributions to fund the construction activities associated with the Texas Express NGL system of approximately $20.1 million.

Offsetting the increase in investing activities discussed above was $178.3 million fewer additions to property, plant and equipment, net of construction payables, for the year ended December 31, 2013 when compared with 2012 as many of our capital projects were put into service in 2013 with less capital projects projected for the future.

Financing Activities

Net cash provided by our financing activities decreased $155.5 million for the year ended December 31, 2013, compared to the year ended December 31, 2012, primarily due to the following:

- Increased net proceeds from our initial public offering in November 2013 of $354.9 million; and
- Increased borrowings, net of repayments, under our Credit Facility of $335.0 million, and

Offsetting the increase in financing activities discussed above were:

- Distributions to EEP of proceeds from the initial public offering in November 2013 and credit facility borrowings of $674.8 million; and
- Decreased capital contributions from our General Partner and its affiliates, net of distributions to our General Partner and its affiliates of $167.6 million in 2013.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On January 29, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable of $0.16644 per unit for the quarter ended December 31, 2013. The distribution was paid on February 14, 2014 to unitholders of record on February 7, 2014. This amount represents the prorated target minimum quarterly distribution of $0.31250 per unit, or $1.25 on an annualized basis, for the period from the completion of the Offering through December 31, 2013. We paid $3.5 million to our public Class A common unitholders, while $4.2 million in the aggregate was paid to EEP with respect to its Class A common units, subordinated units and general partner interest.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-04 which provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Presentation of Unrecognized Tax Benefits

In July 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-11 which requires the presentation of unrecognized tax benefit as a reduction to a deferred tax asset for a net operating loss carry forward unless specific conditions exist. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied prospectively. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our selection and application of accounting policies is an important process that has developed as our business activities have evolved and as new accounting pronouncements have been issued. Accounting decisions generally involve an interpretation of existing accounting principles and the use of judgment in applying those principles to the specific circumstances existing in our business. We make every effort to comply with all applicable accounting principles and believe the proper implementation and consistent application of these principles is critical. However, not all situations we encounter are specifically addressed in the accounting literature. In such cases, we must use our best judgment to implement accounting policies that clearly and accurately present the substance of these situations. We accomplish this by analyzing similar situations and the accounting guidance governing them and consulting with experts about the appropriate interpretation and application of the accounting literature to these situations.

In addition to the above, certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures with respect to contingent assets and liabilities. The basis for our estimates is historical experience, consultation with experts and other sources we believe to be reliable. While we believe our estimates are appropriate, actual results can and often do differ from these estimates. Any effect on our business, financial position, results of operations and cash flows resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

We believe our critical accounting policies and estimates discussed in the following paragraphs address the more significant judgments and estimates we use in the preparation of our consolidated financial statements. Each of these areas involve complex situations and a high degree of judgment either in the application and interpretation of existing accounting literature or in the development of estimates that affect our consolidated financial statements. Our management has discussed the development and selection of the critical accounting policies and estimates related to the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent liabilities with the Audit, Finance & Risk Committee of Enbridge Management's board of directors.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectability is reasonably assured. For our gathering, processing and transportation and logistics and marketing businesses, we must estimate our current month revenue and cost of natural gas to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas based on the best available volume and price data for natural gas delivered and received, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each period reported. We believe that the assumptions underlying these estimates will not be significantly different from the actual amounts due to the routine nature of these estimates and the consistency of our processes.

Within our gathering, processing and transportation business, we receive fee-based revenue for services, such as compression fees, gathering fees and treating fees, which are recognized when volumes are received on our systems. Additionally, revenues of our gathering, processing and transportation business that are derived from transmission services consist of reservation fees charged for transportation of natural gas on some of our intrastate pipeline systems. Customers paying these fees typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transportation volumes. Reservation fees are required to be paid whether or not the shipper delivers the volumes, thus referred to as a ship-or-pay arrangement. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transportation services.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for: (1) assets purchased or constructed; (2) existing assets that are replaced, improved or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the authoritative accounting provisions applicable to regulated operations, an equity return component.

We categorize our capital expenditures as either maintenance or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain our asset base, operating capacity or operating income over the long term or to maintain the existing useful life of any of our capital assets. Examples of maintenance capital expenditures include the replacement of system components and equipment that is worn, obsolete or completing its useful life. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as maintenance capital expenditures. We expect to incur continuing annual maintenance capital expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital expenditures will increase due to the growth of our pipeline systems. We expect to fund maintenance capital expenditures through operating cash flows.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of its estimated useful life or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we recognize a gain or loss in our consolidated statements of income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of income.

Assessment of Recoverability of Goodwill

Goodwill represents the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is allocated to two of our segments, Gathering, Processing and Transportation and Logistics and Marketing.

Pursuant to the authoritative accounting provisions for goodwill and other intangible assets, we do not amortize goodwill, but test it for impairment annually based on carrying values as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may be impaired. In testing goodwill for impairment, we make critical assumptions that include but are not limited to: (1) projections of future financial performance, which include commodity price and volume assumptions; (2) the expected growth rate of our Gathering, Processing and Transportation and Logistics and Marketing assets; (3) residual values of the assets; and (4) market weighted average cost of capital. Impairment occurs when the carrying amount of a reporting unit's goodwill exceeds its implied fair value. We reduce the carrying value of goodwill to its fair value at the time we determine that an impairment has occurred.

Assessment of Recoverability of Intangibles

Our intangible assets primarily consist of customer contracts for the purchase and sale of natural gas, natural gas supply opportunities and contributions we have made in aid of construction activities that will benefit our operations, as well as workforce contracts and customer relationships. We amortize these assets on a straight-line basis over the weighted average useful lives of the underlying assets, representing the period over which the assets are expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our intangible assets whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows we expect the intangibles or the underlying assets to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles and its carrying amount exceeds its fair value, we write the intangibles down to their fair value.

Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value to our derivative instruments and disclosures associated with our outstanding commodity activities. We define fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We employ a hierarchy which prioritizes the inputs we use to measure recurring fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.

- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument, as Level 2. This category includes both over-the-counter, or OTC, transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted prices for assets and liabilities; (b) time value; (c) volatility factors; and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.
- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources (i.e., values supported by lesser volumes of market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 assets and liabilities primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. Additionally, Level 3 valuations may utilize modeled pricing inputs to derive forward valuations, which may include some or all of the following inputs: non-binding broker quotes, time value, volatility, correlation and extrapolation methods.

The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent third party investment dealers who actively make markets in our debt securities, which we use to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

We utilize a mid-market pricing convention, or the "market approach," for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. Our assets are adjusted for the non-performance risk of our counterparties using their current credit default swap spread rates. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and is also adjusted using a credit adjustment model incorporating inputs such as credit default swap rates, bond spreads, and default probabilities. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable master netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in United States dollars, or USD. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments. In accordance with the authoritative accounting guidance, we record all derivative financial instruments to our consolidated statements of financial position at fair market value. We record the fair market value of our derivative financial instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a net basis by counterparty. Derivative balances are shown net of cash collateral received or posted where master netting agreements exist. For those instruments that qualify for hedge accounting under authoritative accounting guidance, the accounting treatment is dependent on the intended use and designation of each instrument. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as "Operating revenue" and "Cost of natural gas and natural gas liquids."

Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by the board of directors of Midcoast Holdings or a committee of senior management appointed by our General Partner. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

Cash flow hedges are derivative financial instruments that qualify for hedge accounting treatment. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions.

Price assumptions we use to value our non-qualifying derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

At inception, we formally document the relationship between the hedging instrument and the hedged item, the risk management objective, and the method used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, we regularly assess the creditworthiness of our counterparties to manage against the risk of default. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

We record the changes in fair value of derivative financial instruments designated and qualifying as effective cash flow hedges as a component of "Accumulated other comprehensive income" until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in fair market value is recognized immediately in earnings.

Our earnings are also affected by use of the mark-to-market method of accounting as required under GAAP. We use derivative financial instruments such as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions. However, these derivative financial instruments often do not qualify for hedge accounting treatment under authoritative accounting guidance, and as a result we record changes in the fair value of these instruments on the statement of financial position and through earnings rather than deferring them until the firm commitment or anticipated transactions affect earnings. The use of mark-to-market accounting for derivative financial instruments can cause non-cash earnings volatility resulting from changes in the underlying indices, primarily commodity prices.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in "Other long-term liabilities" in our consolidated statements of financial position at their undiscounted amounts. We always have the potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as such costs are incurred.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

COMMODITY PRICE RISK

Our exposure to commodity price risk exists within our Gathering Processing and Transportation and Logistics and Marketing segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

		At December 31, 2013					At December 31, 2012	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	536,870	$ 4.26	$ 4.27	$ —	$ —	$ —	$ —
	NGL	631,250	$69.29	$68.99	$ 0.6	$ (0.4)	$ —	$ —
	Crude Oil	—	$ —	$ —	$ —	$ —	$ —	$ (5.0)
Receive fixed/pay variable	Natural Gas	4,478,991	$ 3.94	$ 4.14	$ 0.1	$ (1.0)	$ 0.2	$ —
	NGL	2,659,300	$54.80	$57.77	$ 4.8	$(12.7)	$ 0.9	$ (2.7)
	Crude Oil	1,066,950	$90.85	$95.71	$ 0.3	$ (5.4)	$ 5.4	$ (2.7)
Receive variable/pay variable	Natural Gas	32,752,500	$ 4.12	$ 4.11	$ 0.6	$ (0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,083,450	$47.81	$47.77	$ 0.9	$ (0.9)	$ —	$ —
	Crude Oil	50,700	$98.47	$98.10	$ —	$ —	$ —	$ —
Receive fixed/pay variable	NGL	1,335,534	$46.80	$48.44	$ 0.4	$ (2.6)	$ —	$ —
	Crude Oil	165,200	$96.08	$98.48	$ —	$ (0.4)	$ —	$ —
Receive variable/pay variable	Natural Gas	41,064,012	$ 4.21	$ 4.20	$ 0.9	$ (0.4)	$ 0.5	$ —
	NGL	9,337,617	$40.45	$40.23	$ 5.8	$ (3.7)	$ —	$ —
	Crude Oil	998,423	$97.16	$97.33	$ 1.1	$ (1.2)	$ —	$ —
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	565,750	$51.33	$50.56	$ 1.5	$ (1.1)	$ 0.7	$ (0.2)
	Crude Oil	350,400	$93.00	$88.07	$ 1.7	$ —	$ 6.8	$ (0.2)
Receive variable/pay variable	Natural Gas	4,707,500	$ 4.02	$ 4.01	$ 0.1	$ —	$ —	$ —
Receive variable/pay fixed	Crude Oil	—	$ —	$ —	$ —	$ —	$ —	$ (5.6)
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,802,925	$ 4.19	$ 4.14	$ 0.5	$ (0.1)	$ 0.4	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$99.31	$83.41	$ 0.7	$ —	$ 0.5	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	996,740	$ 4.23	$ 4.13	$ 0.1	$ —	$ 0.1	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2013 and December 31, 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of gains at December 31, 2013 and $0.2 million of losses at December 31, 2012.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2013 and 2012.

	At December 31, 2013						At December 31, 2012	
					Fair Value [3]		Fair Value[3]	
	Commodity	Notional[1]	Strike Price[2]	Market Price[2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2014								
Puts (purchased)	Natural Gas	1,825,000	$ 3.90	$ 4.19	$ 0.2	$—	$—	$—
	NGL	493,500	$51.91	$53.47	$ 2.9	$—	$ 1.3	$—
Calls (written)	NGL	273,750	$57.93	$53.35	$—	$(1.0)	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.14	$ 1.7	$—	$—	$—
	NGL	930,750	$53.57	$55.13	$ 6.0	$—	$—	$—
	Crude Oil	273,750	$85.00	$87.74	$ 1.8	$—	$—	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.14	$—	$(0.3)	$—	$—
	NGL	109,500	$81.90	$81.24	$—	$(1.0)	$—	$—
	Crude Oil	273,750	$90.25	$87.74	$—	$(1.9)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2013 and 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

QUALITATIVE FACTORS

Hedge Accounting

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply a mid-market pricing convention, which we refer to as the market approach, to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimates of fair value.

In accordance with the applicable authoritative accounting guidance, if a derivative financial instrument does not qualify as a cash flow hedge, or is not designated as a cash flow hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in "cost of natural gas and natural gas liquids" or "operating revenue" for our commodity-based derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in "Accumulated other comprehensive income," also referred to as AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement until the underlying transaction occurs. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in "cost of natural gas and natural gas liquids" for commodity hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have derivative financial instruments associated with our commodity activities where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "cost of natural gas and natural gas liquids or operating revenue" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to volatility in our earnings and in our cash flows upon settlement:

Commodity Price Exposures:

- **Transportation—**In our logistics and marketing business, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.
- **Storage—**In our logistics and marketing business, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the natural gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas or NGLs are recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas and NGL storage activities can increase volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

- **Optional Natural Gas Processing Volumes**—In our gathering, processing and transportation business, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL Forward Contracts**—In our logistics and marketing business, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. A sub-group of physical NGL sales contracts qualify for the normal purchases and normal sales, or NPNS, scope exception. All other forward contracts are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.
- **Natural Gas Forward Contracts—**In our logistics and marketing business, we use forward contracts to sell natural gas to our customers. Certain physical natural gas contracts with terms allowing for economic net settlement are being marked to market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Crude Forward Contracts—**In our logistics and marketing business, we use forward contracts to fix the price of crude we purchase and store in inventory and to fix the price of crude that we sell from inventory. A sub-group of physical crude contracts with terms allowing for economic net settlement do not qualify for the NPNS, scope exception and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in crude prices until the forward contracts are settled.
- **Natural Gas and NGL Options**—In our gathering, processing and transportation business, we use options to hedge the forecasted commodity exposure of our NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to volatility due to movements in the prices of NGLs and natural gas until the underlying long-term transactions are settled.

In all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical cost or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31,	
	2013	2012
	(in millions)	
Other current assets and Due from General Partner and affiliates	$ 10.3	$ 275.0
Other assets, net	10.3	78.1
Accounts payable and other and Due to General Partner and affiliates	(21.1)	(259.9)
Other long-term liabilities	(0.9)	(78.0)
	$ (1.4)	$ 15.2

The changes in the net assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $0.7 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the years ended December 31, 2013 and 2012, commodity hedge gains of $1.7 million and losses of $6.3 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $10.5 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2013, will be reclassified from AOCI to earnings during the next 12 months.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	December 31,	
	2013	2012
	(in millions)	
Counterparty Credit Quality[1]		
AAA	$ 0.2	$ —
AA	(2.1)	(116.6)
A	(1.1)	(150.4)
Lower than A	1.6	282.2
	$(1.4)	$ 15.2

[1] As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. As of December 31, 2013 and December 31, 2012, we were not holding any cash collateral on our asset exposures. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At December 31, 2013 and 2012, we had credit concentrations in the following industry sectors, as presented below:

	December 31,	
	2013	2012
	(in millions)	
United States financial institutions and investment banking entities	$ 2.4	$(204.7)
Non-United States financial institutions	0.1	(87.4)
Integrated oil companies	(1.6)	4.5
General Partner and affiliates	(0.1)	297.2
Other	(2.2)	5.6
	$(1.4)	$ 15.2

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs, and Crude) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts —Financial							
Natural Gas	$(0.0)	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	$(6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	$(0.5)	Market Approach	Forward Crude Price	86.37	103.04	97.24	Bbl
NGLs	$(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 2.0						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.1 million of gains.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2012[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts —Financial							
Natural Gas	$ 8.8	Market Approach	Forward Gas Price	3.21	4.31	3.54	MMBtu
NGLs	$ (0.4)	Market Approach	Forward NGL Price	0.25	2.21	1.40	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.7	Market Approach	Forward Gas Price	3.19	4.58	3.73	MMBtu
Crude Oil	$ 2.6	Market Approach	Forward Crude Price	65.22	116.56	94.31	Bbl
NGLs	$ 3.1	Market Approach	Forward NGL Price	—	2.22	0.61	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 6.4	Option Model	Option Volatility	29%	104%	40%	
Total Fair Value	$22.2						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.

(2) Fair values are presented in millions and include credit valuation adjustments of approximately $0.1 million of losses.

Item 8. Financial Statements and Supplementary Data

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FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this report have been omitted because they are not applicable or the required information is either immaterial or shown in the consolidated financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Partners of Midcoast Energy Partners, L.P.:

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, comprehensive income, partners' capital and cash flows present fairly, in all material respects, the financial position of Midcoast Energy Partners, L.P. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 17, 2014

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	For the year ended December 31,		
	2013	2012	2011
	(in millions, except per unit amounts)		
Operating revenue (Notes 12 and 14)	$5,380.5	$4,961.7	$7,505.2
Operating revenue—affiliate	213.1	396.2	323.0
	5,593.6	5,357.9	7,828.2
Operating expenses:			
Cost of natural gas and natural gas liquids (Notes 6, 12 and 14)	4,817.5	4,294.6	6,864.6
Cost of natural gas and natural gas liquids—affiliate	119.6	289.5	202.0
Operating and maintenance (Notes 2, 12 and 13)	271.6	252.2	217.3
Operating and maintenance—affiliate	78.7	110.1	100.5
General and administrative	—	7.9	0.2
General and administrative—affiliate	98.2	97.2	81.6
Depreciation and amortization (Note 7)	142.9	135.0	142.7
	5,528.5	5,186.5	7,608.9
Operating income	65.1	171.4	219.3
Interest expense (Notes 10 and 14)	1.7	—	—
Other income (expense) (Note 13)	(1.2)	(0.1)	2.8
Income before income tax expense	62.2	171.3	222.1
Income tax expense (Note 15)	8.3	3.8	2.9
Net income	$ 53.9	$ 167.5	$ 219.2
Less: Predecessor income prior to initial public offering (from January 1, 2013 through November 12, 2013)	56.3		
Net loss subsequent to initial public offering to Midcoast Energy Partners, L.P. (from November 13, 2013 through December 31, 2013)	(2.4)		
Less: Net loss attributable to noncontrolling interest subsequent to initial public offering	(0.6)		
Net loss attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P. subsequent to initial public offering	$ (1.8)		
Net income attributable to limited partner ownership interest	$ 19.7	$ 64.0	$ 83.8
Net income per limited partner unit (basic and diluted)	$ 0.68	$ 2.40	$ 3.14
Weighted average limited partner units outstanding	29.2	26.7	26.7

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

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the year ended December 31,		
	2013	2012	2011
		(in millions)	
Net income	$ 53.9	$167.5	$219.2
Other comprehensive income (loss), net of tax expense (benefit) of $(0.1), $0.2, and $0.2, respectively (Note 14)	(10.2)	35.8	22.7
Comprehensive income	43.7	203.3	241.9
Less: Comprehensive income attributable to:			
Noncontrolling interest (Note 12)	(0.6)	—	—
Other comprehensive income (loss) allocated to noncontrolling interest	(3.3)	—	—
Comprehensive income attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 41.0	$203.3	$241.9

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

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the year ended December 31,		
	2013	2012	2011
		(in millions)	
Cash provided by operating activities			
Net income	$ 53.9	$ 167.5	$ 219.2
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization (Note 7)	142.9	135.0	142.7
Derivative fair value net losses (gains) (Note 14)	3.0	(1.2)	(16.5)
Inventory market price adjustments (Note 6)	3.4	9.8	3.6
Deferred income taxes (Note 15)	7.3	0.1	0.2
Other (Note 17)	1.3	3.5	8.8
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	7.9	67.8	(0.6)
Due from General Partner and affiliates	(633.9)	4.5	0.4
Accrued receivables	295.6	(68.2)	178.4
Inventory (Note 6)	(12.2)	12.0	24.3
Current and long-term other assets (Note 14)	(14.3)	(4.5)	(3.1)
Due to General Partner and affiliates (Note 12)	522.8	17.9	13.6
Accounts payable and other (Notes 5 and 14)	34.6	2.1	(33.6)
Accrued purchases	4.9	6.4	(125.5)
Interest payable	0.3	—	—
Property and other taxes payable	3.4	—	3.7
Net cash provided by operating activities	420.9	352.7	415.6
Cash used in investing activities			
Additions to property, plant and equipment (Note 7)	(273.4)	(451.7)	(441.5)
Changes in restricted cash (Note 12)	(61.5)	—	—
Asset acquisitions	(0.9)	—	(30.7)
Proceeds from the sale of net assets	5.0	9.2	—
Investment in joint venture	(188.6)	(168.5)	(10.7)
Other	(2.9)	(3.5)	2.8
Net cash used in investing activities	(522.3)	(614.5)	(480.1)
Cash provided by financing activities			
Borrowings under credit facility (Note 10)	1,229.8	—	—
Repayments under credit facility (Note 10)	(894.8)	—	—
Debt origination fees (Note 10)	(3.0)	—	—
Net proceeds from unit issuances (Note 10)	354.9	—	—
Contributions from partners (Note 11)	341.9	564.0	406.9
Distributions to partners (Note 11)	(247.7)	(302.2)	(342.4)
Distribution to EEP for net assets contributed (Note 11 or 12)	(674.8)	—	—
Net cash provided by financing activities	106.3	261.8	64.5
Net increase in cash and cash equivalents	4.9	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of period	$ 4.9	$ —	$ —

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

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2013	December 31, 2012
	(in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 4.9	$ —
Restricted cash (Note 12)	61.5	—
Receivables, trade and other, net of allowance for doubtful accounts of $0.5 in 2013 and $1.9 in 2012 (Note 13)	50.3	26.2
Due from General Partner and affiliates	654.8	263.5
Accrued receivables	182.2	551.2
Inventory (Note 6)	88.0	74.8
Other current assets (Note 14)	19.1	32.5
	1,060.8	948.2
Property, plant and equipment, net (Notes 7 and 12)	4,082.3	3,963.0
Goodwill (Note 8)	226.5	226.5
Intangibles, net (Note 9)	255.0	257.2
Equity Investment in Joint Venture	371.3	183.7
Other assets, net (Note 14)	40.5	88.8
	$6,036.4	$5,667.4
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 534.3	$ 41.3
Accounts payable and other (Notes 5 and 14)	114.4	314.5
Accrued purchases	463.3	494.3
Interest payable	0.3	—
Property and other taxes payable (Note 15)	19.8	16.4
	1,132.1	866.5
Long-term debt (Note 10)	335.0	—
Other long-term liabilities (Notes 13, 14 and 15)	16.6	86.7
	1,483.7	953.2
Commitments and contingencies (Note 13)		
Partners' capital (Notes 11 and 12)		
Predecessor partner interest	—	4,707.1
Class A common units (22,610,056 authorized and issued at December 31, 2013)	495.3	—
Subordinated units (22,610,056 authorized and issued at December 31, 2013)	1,035.1	—
General Partner units (922,859 authorized and issued at December 31, 2013)	42.2	—
Accumulated other comprehensive income (loss) (Note 14)	(3.1)	7.1
Total Midcoast Energy Partners, L.P. partners' capital	1,569.5	4,714.2
Noncontrolling interest (Note 12)	2,983.2	—
Total partners' capital	4,552.7	4,714.2
	$6,036.4	$5,667.4

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

MIDCOAST ENERGY PARTNERS' L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	For the year ended December 31,					
	2013		2012		2011	
	Units	Amount	Units	Amount	Units	Amount
		(in millions, except unit amounts)				
Class A common units:						
Beginning balance	—	$ —	—	$ —	—	$ —
Allocation of limited partner interests	1,335,056	282.4	—	—	—	—
Proceeds from IPO	21,275,000	354.9	—	—	—	—
Distribution of proceeds (from IPO and credit facility)	—	(141.1)	—	—	—	—
Net income (loss) allocation from November 13 through December 31, 2013	—	(0.9)	—	—	—	—
Ending balance	22,610,056	495.3	—	—	—	—
Subordinated units:						
Beginning balance	—	—	—	—	—	—
Allocation of limited partner interests	22,610,056	1,548.8	—	—	—	—
Distribution of proceeds (from IPO and credit facility)	—	(512.8)	—	—	—	—
Net income (loss) allocation	—	(0.9)	—	—	—	—
Distributions	—	—	—	—	—	—
Ending balance	22,610,056	1,035.1	—	—	—	—
General Partner:						
Beginning balance	—	—		—		—
Allocation of limited partner interests	922,859	63.1		—		—
Distribution of proceeds (from IPO and credit facility)	—	(20.9)		—		—
Net income allocation	—	—		—		—
Ending balance	922,859	42.2		—		—
Predecessor Partner Interest:						
Beginning balance		4,707.1		4,277.8		3,994.1
Net income (loss) allocation through November 13		56.3		167.5		219.2
Contribution		341.9		564.0		406.9
Distributions		(247.7)		(302.2)		(342.4)
Allocation of limited partner interests		(4,857.6)		—		—
Ending balance		—		4,707.1		4,277.8
Accumulated other comprehensive income:						
Beginning balance		7.1		(28.7)		(51.4)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings		(2.7)		(0.1)		59.3
Unrealized net loss on derivative financial instruments		(7.5)		35.9		(36.6)
Ending balance		(3.1)		7.1		(28.7)
Total Midcoast Energy Partners, L.P. partners' capital at December 31,		1,569.5		4,714.2		4,249.1
Noncontrolling interest:						
Beginning balance		—		—		—
Allocation of limited partner interests		2,963.0		—		—
Capital contributions		24.1		—		—
Comprehensive income:						
Net income allocation		(0.6)		—		—
Other comprehensive income, net of tax		(3.3)		—		—
Distributions		—		—		—
Ending balance		2,983.2		—		—
Total partners' capital at December 31,		$ 4,552.7		$4,714.2		$4,249.1

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

MIDCOAST ENERGY PARTNERS, L.P.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND NATURE OF OPERATIONS

Initial Public Offering

Midcoast Energy Partners, L.P., or MEP, is a limited partnership formed by Enbridge Energy Partners, L.P, or EEP, to serve as EEP's primary vehicle for owning and growing its natural gas and natural gas liquids midstream business in the United States. On November 13, 2013, MEP completed its initial public offering, or the Offering, of 18,500,000 Class A common units (2,775,000 additional Class A common units were issued pursuant to the exercise of the underwriters' over-allotment option on December 9, 2013), representing limited partner interests. On the same date, in connection with the closing of the Offering, certain transactions, among others, occurred pursuant to which EEP effectively conveyed to MEP (1) all of its limited liability company interests in Midcoast OLP GP, L.L.C. (the general partner of Midcoast Operating, L.P., or Midcoast Operating) and (2) a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units, MEP Subordinated Units, a right to receive $323.4 million in cash, and approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the conveyed businesses. MEP received proceeds (net of underwriting discounts, structuring fees and offering expenses) from the Offering of approximately $354.9 million. MEP used the net proceeds to distribute approximately $304.5 million to EEP, to pay approximately $3.4 million in revolving credit facility origination and commitment fees and used approximately $47.0 million to redeem 2,775,000 Class A common units from EEP. Following the completion of the Offering, EEP continues to own crude oil and liquid petroleum assets and a 61% non-controlling interest in Midcoast Operating. EEP also retained a significant interest through its ownership of our General Partner, a 52% limited partner interest, after the exercise of the over-allotment option, in us and all of our incentive distribution rights. The Class A common units began trading on November 7, 2013 on the New York Stock Exchange, or NYSE, under the ticker symbol MEP.

Unless the context otherwise requires, references in this report to the Predecessor, we, our, us, or like terms, when used in a historical context (periods prior to November 13, 2013), refer to Midcoast Operating. References in this report to Midcoast Energy Partners, the Partnership, MEP, we, our, us, or like terms used in the present tense or prospectively (periods beginning on or after November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries.

General

We own and operate a portfolio of assets engaged in the business of gathering, processing and treating natural gas, as well as the transportation and marketing of natural gas, natural gas liquids, or NGLs, and condensate. Our portfolio of natural gas and NGL pipelines, plants and related facilities are geographically concentrated in the Gulf Coast and Mid-Continent regions of the United States, primarily in Texas and Oklahoma. We also own and operate natural gas and NGL logistics and marketing assets that primarily support our gathering, processing and transportation business. We hold our assets in a series of limited partnerships and limited liability companies that we wholly own, either directly or indirectly.

Prior to the Offering, our capital accounts consisted of general partner interests held by Midcoast OLP GP, L.L.C (f/k/a Enbridge Midcoast Holdings, L.L.C.), or the OLP GP, which was a wholly owned subsidiary of EEP, and limited partner interests held directly by EEP. At December 31, 2012 and 2011 our equity interests were distributed as follows:

	2012	2011
Limited Partner interest	99.999%	99.999%
General Partner interest	0.001%	0.001%

As of December 31, 2013, our capital accounts consist of general partner interests held by Midcoast Holdings, L.L.C., or Midcoast Holdings, which is a wholly owned subsidiary of EEP, and limited partner interests held by EEP and the public. At December 31, 2013 our equity interests were distributed as follows:

	2013
Limited Partner Interests held by EEP	52%
Limited Partner Interests held by the Public	46%
General Partner Interest	2%
	100%

Enbridge Energy Partners, L.P.

EEP was formed in 1991 by Enbridge Energy Company, Inc., its general partner, an indirect, wholly-owned subsidiary of Enbridge Inc., which we refer to as Enbridge, a leading energy transportation and distribution company located in Calgary, Alberta, Canada. EEP was formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership, which owns the United States portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada.

EEP is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets and, through its ownership interests in us, natural gas gathering, treating, processing, transmission and marketing assets in the United States of America. EEP's Class A common units are traded on the New York Stock Exchange, or NYSE, under the symbol "EEP."

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C., which we refer to as Enbridge Management, is a Delaware limited liability company that was formed by Enbridge Energy Company, Inc. in May 2002. EEP's general partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management's listed shares are traded on the NYSE under the symbol EEQ. Enbridge Management owns all of a special class of EEP's limited partner interests and derives all of its earnings from its investment in EEP.

Enbridge Management's principal activity is managing the business and affairs of EEP pursuant to a delegation of control agreement among EEP's general partner, Enbridge Management and EEP. In accordance with its limited liability company agreement, Enbridge Management's activities are restricted to being a limited partner of EEP and managing its business and affairs.

Enbridge Inc.

Enbridge is the indirect parent of EEP's general partner, and its common shares are publicly traded on the NYSE in the United States and on the Toronto Stock Exchange in Canada, in each case, under the symbol ENB. Enbridge is a leader in energy transportation and distribution in North America, with a focus on crude oil and liquids pipelines, natural gas pipelines, natural gas distribution and renewable energy. At December 31, 2013 and 2012, Enbridge and its consolidated subsidiaries held an effective 11.1% and 21.8% interest in MEP, respectively, through its indirect ownership in Enbridge Management and EEP's general partner.

Business Segments

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing.

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. We gather natural gas from the wellhead and central receipt points on our systems, deliver it to our facilities for processing and treating and deliver the residue gas to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies. We deliver the NGLs produced at our processing and fractionation facilities to intrastate and interstate pipelines for transportation to the NGL market hubs in Mont Belvieu, Texas and Conway, Kansas.

Our gathering, processing and transportation business primarily consists of our Anadarko system, the East Texas system and the North Texas system, which provide natural gas gathering, processing, transportation and related services predominantly in active producing basins in east and north Texas, as well as the Texas Panhandle and western Oklahoma. At December 31, 2013, our Gathering, Processing and Transportation business included eight active and four standby natural gas treating plants and 21 active and four standby natural gas processing plants, excluding plants that are inactive based on current volumes. In addition, our Gathering, Processing and Transportation business includes approximately 11,600 miles of natural gas gathering and transmission lines and approximately 222 miles of NGL gathering and transportation lines.

On October 31, 2013, Midcoast Energy Partners L.P., Enterprise Product Partners L.P., or Enterprise, Anadarko Petroleum Corporation, or Anadarko, and DCP Midstream Partners, LP, or DCP Midstream, announced the start of service on the Texas Express NGL system, which consists of two separate joint ventures with third parties to design and construct a new NGL pipeline, or mainline, and NGL gathering system. The joint venture ownership of the mainline portion of the Texas Express NGL system is owned 35% by Enterprise, 35% by us, 20% by Anadarko and 10% by DCP Midstream. The joint venture ownership of the new NGL gathering system is owned 45% by Enterprise, 35% by us and 20% by Anadarko. Enterprise constructed and serves as the operator of the mainline, while we constructed and operate the new gathering system.

The Texas Express NGL pipeline originates near Skellytown, Texas in the Texas Panhandle and extends approximately 580 miles to NGL fractionation and storage facilities in the Mont Belvieu area on the Texas Gulf Coast. The mainline has an initial capacity of approximately 280,000 Bpd and is expandable to approximately 400,000 Bpd with additional pump stations on the system. There are currently capacity reservations on the mainline that, when fully phased in, will total approximately 250,000 Bpd.

Logistics and Marketing

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business, thereby enhancing our competitive position. In addition, our logistics and marketing services provide our customers with the opportunity to receive enhanced economics by providing access to premium markets through the transportation capacity and other assets we control. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from pipeline systems and processing plants and sells and delivers them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, or U.S. GAAP. Our preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingent assets and liabilities. We regularly evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the circumstances. Nevertheless, actual results may differ significantly from these estimates. We record the effect of any revisions to these estimates in our consolidated financial statements in the period in which the facts that give rise to the revision become known.

Principles of Consolidation

The consolidated financial statements include our accounts and those of our wholly and majority-owned subsidiaries on a consolidated basis. All significant intercompany accounts and transactions have been eliminated in consolidation. We consolidate the accounts of entities over which we have a controlling financial interest through our ownership of the General Partner or the majority voting interests of the entity. Our 35% ownership interests in Texas Express Pipeline, L.L.C. and Texas Express Gathering, L.L.C. are accounted for under the equity method of accounting as a result of our ability to significantly influence the operating activities of these entities, but insufficient ability to control these activities without the participation of a majority of the other members.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas and Natural Gas Liquids

Gathering, Processing and Transportation

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectability is reasonably assured. We derive revenue in our Gathering, Processing and Transportation business from the following types of arrangements:

Equity Investment in Joint Venture

Our natural gas business includes our 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties, representing a 580-mile NGL intrastate transportation pipeline and a related NGL gathering system. We use the equity method of accounting for our 35% joint venture interest in the Texas Express NGL system as a result of our ability to significantly influence the operating activities, but insufficient ability to control these activities without the participation of a majority of the other members.

Fee-Based Arrangements

In a fee-based arrangement, we receive a fee per Mcf of natural gas processed or per gallon of NGLs produced. Under this arrangement, we have no direct commodity price exposure. Within our gathering, processing and transportation business, we receive fee-based revenue for services, such as compression fees, gathering fees and treating fees, which are recognized when volumes are received on our systems. Additionally, revenues of our gathering, processing and transportation business that are derived from transmission services consist of reservation fees charged for transportation of natural gas on some of our intrastate pipeline systems. Customers paying these fees typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transportation volumes. Reservation fees are required to be paid whether or not the shipper delivers the volumes, thus referred to as a ship-or-pay arrangement. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transportation services.

Make-up rights

Some long-term ship-or-pay contracts contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiration periods. We recognize revenue associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Commodity-Based Arrangements

We also generate revenue and segment gross margin under other types of service arrangements with customers. These arrangements expose us to commodity price risk, which we mitigate to a substantial degree with the use of derivative financial instruments to hedge open positions in these commodities. We hedge a significant amount of our exposure to commodity price risk to support the stability of our cash flows. We provide additional information in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk* and Note 14. *Derivative Financial Instruments and Hedging Activities* of our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* of this report about the derivative activities we use to mitigate our exposure to commodity price risk.

The commodity-based service contracts we have with customers are categorized as follows:

- *Percentage-of-Proceeds Contracts*—Under these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we can sell at market prices and retain the proceeds as our compensation. This type of arrangement exposes us to commodity price risk, as the revenues from percentage-of-proceeds contracts directly correlate with the market prices of the applicable commodities that we receive.
- *Percentage-of-Liquids Contracts*—Under these contracts, we receive a negotiated percentage of the NGLs extracted from natural gas that require processing, which we can then sell at market prices and retain the proceeds as our compensation. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGLs produced. This type of contract may also require us to provide the customer with a guaranteed NGL recovery percentage regardless of actual NGL production. Since revenues from percentage-of-liquids contracts directly correlate with the market price of NGLs, this type of arrangement also exposes us to commodity price risk.
- *Percentage-of-Index Contracts*—Under these contracts, we purchase raw natural gas at a negotiated percentage of an agreed upon index price. We then resell the natural gas, generally for the index price, and keep the difference as our compensation.
- *Keep-Whole Contracts*—Under these contracts, we gather or purchase raw natural gas from the customer. We extract and retain the NGLs produced during processing for our own account, which we then sell at market prices. In instances where we purchase raw natural gas at the wellhead, we may also sell the resulting residue natural gas for our own account at market prices. In those instances when we gather and process raw natural gas for the customer's account, we generally must return to the customer residue natural gas with an energy content equivalent to the original raw natural gas we received, as measured in British thermal units, or Btu. This type of arrangement has the highest commodity price exposure because our costs are dependent on the price of natural gas purchased and our revenues are dependent on the price of NGLs sold. As a result, we benefit from these types of contracts when the value of the NGLs is high relative to the cost of the natural gas and are disadvantaged when the cost of the natural gas is high relative to the value of the NGLs.

Under the terms of each of our commodity-based service contracts, we retain natural gas and NGLs as our compensation for providing these customers with our services. As of December 31, 2013, we are exposed to fluctuations in commodity prices in the near term on approximately 35% to 40% of the natural gas, NGLs and condensate we expect to receive as compensation for our services. Due to this unhedged commodity price exposure, our segment gross margin, representing revenue less cost of natural gas, generally increases when the prices of these commodities are rising and generally decreases when the prices are declining. As a result of entering into these derivative instruments, we have largely fixed the amount of cash that we will pay and receive in the future when we sell the residue gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate. Many of the derivative financial instruments we use do not qualify for hedge accounting. As a result we record the changes in fair value of the derivative instruments that do not qualify for hedge accounting in our operating results. This accounting treatment produces non-cash gains and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile.

Logistics and Marketing

Our logistics and marketing business derives a majority of its segment gross margin from purchasing and receiving natural gas, NGLs and other products from our gathering, processing and transportation business and from third-party pipeline systems and processing plants and selling and delivering them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants. We contract for third-party pipeline capacity under firm and interruptible transportation contracts for which the pipeline capacity depends on volumes of natural gas from our natural gas assets, which provides us with access to several third-party interstate and intrastate pipelines that can be used to transport natural gas and NGLs to primary market hubs where they can be sold to major customers for these products. Our logistics and marketing business also uses owned and leased trucks and specialized trailers and railcars to transport products such as NGLs, condensate and other liquid hydrocarbons to market. In some instances, our margin per unit of volume sold can be higher if the commodity being marketed requires specialized handling, treating, stabilization or other services.

Our logistics and marketing business also derives segment gross margin from the relative difference in natural gas and NGL prices between the contracted index at which the natural gas and NGLs are purchased and the index price at which they are sold, otherwise known as the "basis spread," which can vary over time or by location, as well as due to local supply and demand factors. Natural gas and NGLs purchased and sold by our logistics and marketing business is primarily priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. We enter into long-term, fixed-price purchase or sales contracts with our customers and generally will enter into offsetting hedge positions under the same or similar terms.

Estimation of Revenue and Cost of Natural Gas and Natural Gas Liquids

For our gathering, processing and transportation business, as well as our logistics and marketing business, we must estimate our current month revenue and cost of natural gas and natural gas liquids to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to our preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas and natural gas liquids based on the best available volume and price data for natural gas and natural gas liquids delivered and received, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas and natural gas liquids for each of the years ended December 31, 2013, 2012 and 2011. We believe that the assumptions underlying these estimates are not significantly different from the actual amounts due to the routine nature of these estimates and the consistency of our processes.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with original maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not been presented to the financial institution are included in "Accounts payable and other" on our consolidated statements of financial position.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable when we determine that we will not collect all or part of an outstanding balance. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method.

Inventory

Inventory includes product inventory and materials and supplies inventory. We record all product inventories at the lower of our cost, as determined on a weighted average basis, or market value. Our product inventory consists of natural gas and liquid hydrocarbons, such as NGLs and condensate. Upon disposition, product inventory is recorded to "Cost of natural gas and natural gas liquids" at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

Materials and supplies inventory is either used during operations and charged to "Operating and maintenance" as incurred, or used for capital projects and new construction, and capitalized to "Property, plant and equipment, net."

Operational Balancing Agreements and Natural Gas Imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of natural gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a natural gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in-kind through the receipt or delivery of natural gas in the future. Natural gas imbalances are recorded as "Accrued receivables" and "Accrued purchases" on our consolidated statements of financial position using the posted index prices, which approximate market rates, or our weighted average cost of natural gas.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for: (1) assets purchased or constructed; (2) existing assets that are replaced, improved or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the authoritative accounting provisions applicable to regulated operations, an equity return component.

We categorize our capital expenditures as either maintenance or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain our asset base, operating capacity or operating income over the long term or to maintain the existing useful life of any of our capital assets. Examples of maintenance capital expenditures include the replacement of system components and equipment that is worn, obsolete or completing its useful life. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as maintenance capital expenditures. We expect to incur continuing annual maintenance capital expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital expenditures will increase due to the growth of our pipeline systems. We expect to fund maintenance capital expenditures through operating cash flows.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of its estimated useful life or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we recognize a gain or loss in our consolidated statements of income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of income.

Assessment of Recoverability of Goodwill

Goodwill represents the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is allocated to two of our segments, Gathering, Processing and Transportation and Logistics and Marketing.

Pursuant to the authoritative accounting provisions for goodwill and other intangible assets, we do not amortize goodwill, but test it for impairment annually based on carrying values as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may be impaired. In testing goodwill for impairment, we make critical assumptions that include but are not limited to: (1) projections of future financial performance, which include commodity price and volume assumptions; (2) the expected growth rate of our Gathering, Processing and Transportation and Logistics and Marketing assets; (3) residual values of the assets; and (4) market weighted average cost of capital. Impairment occurs when the carrying amount of a reporting unit's goodwill exceeds its implied fair value. We reduce the carrying value of goodwill to its fair value at the time we determine that an impairment has occurred.

Assessment of Recoverability of Intangibles

Our intangible assets primarily consist of customer contracts for the purchase and sale of natural gas, natural gas supply opportunities and contributions we have made in aid of construction activities that will benefit our operations, as well as workforce contracts and customer relationships. We amortize these assets on a straight-line basis over the weighted average useful lives of the underlying assets, representing the period over which the assets are expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our intangible assets whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows we expect the intangibles or the underlying assets to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles and its carrying amount exceeds its fair value, we write the intangibles down to their fair value.

Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value to our derivative instruments and disclosures associated with our outstanding commodity activities. We define fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We employ a hierarchy which prioritizes the inputs we use to measure recurring fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.
- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument, as Level 2. This category includes both over-the-counter, or OTC, transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted prices for assets and liabilities; (b) time value; (c) volatility factors; and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.
- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources (i.e., values supported by lesser volumes of market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 assets and liabilities primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. Additionally, Level 3 valuations may utilize modeled pricing inputs to derive forward valuations, which may include some or all of the following inputs: non-binding broker quotes, time value, volatility, correlation and extrapolation methods.

The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent third party investment dealers who actively make markets in our debt securities, which we use to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

We utilize a mid-market pricing convention, or the "market approach," for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. Our assets are adjusted for the non-performance risk of our counterparties using their current credit default swap spread rates. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and is also adjusted using a credit adjustment model incorporating inputs such as credit default swap rates, bond spreads, and default probabilities. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable master netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

Income Taxes

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the State of Texas. This tax is computed on our modified gross margin and we have determined the tax to be income taxes as set forth in the authoritative accounting guidance.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. We record the impact of changes in tax legislation on deferred income tax liabilities and assets in the period the legislation is enacted.

Pursuant to the authoritative accounting guidance for accounting for uncertainty in income taxes, we recognize the tax effects of any uncertain tax positions as the largest amount that will more likely than not be realized upon ultimate settlement with a taxing authority having full knowledge of the position and all relevant facts. The Partnership recognizes accrued interest income related to unrecognized tax benefits in interest income when the related unrecognized tax benefits are recognized.

Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in us is not available.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in United States dollars, or USD. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments. In accordance with the authoritative accounting guidance, we record all derivative financial instruments to our consolidated statements of financial position at fair market value. We record the fair market value of our derivative financial instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a net basis by counterparty. Derivative balances are shown net of cash collateral received or posted where master netting agreements exist. For those instruments that qualify for hedge accounting under authoritative accounting guidance, the accounting treatment is dependent on the intended use and designation of each instrument. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as "Operating revenue" and "Cost of natural gas and natural gas liquids."

Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by the board of directors of Midcoast Holdings or a committee of senior management appointed by our General Partner. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

Cash flow hedges are derivative financial instruments that qualify for hedge accounting treatment. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions.

Price assumptions we use to value our non-qualifying derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

At inception, we formally document the relationship between the hedging instrument and the hedged item, the risk management objective, and the method used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, we regularly assess the creditworthiness of our counterparties to manage against the risk of default. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

We record the changes in fair value of derivative financial instruments designated and qualifying as effective cash flow hedges as a component of "Accumulated other comprehensive income" until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in fair market value is recognized immediately in earnings.

Our earnings are also affected by use of the mark-to-market method of accounting as required under GAAP. We use derivative financial instruments such as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions. However, these derivative financial instruments often do not qualify for hedge accounting treatment under authoritative accounting guidance, and as a result we record changes in the fair value of these instruments on the statement of financial position and through earnings rather than deferring them until the firm commitment or anticipated transactions affect earnings. The use of mark-to-market accounting for derivative financial instruments can cause non-cash earnings volatility resulting from changes in the underlying indices, primarily commodity prices.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in "Other long-term liabilities" in our consolidated statements of financial position at their undiscounted amounts. We always have the potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as such costs are incurred.

Asset Retirement Obligations

Legal obligations exist for a minority of our right-of-way agreements due to requirements or landowner options that compel us to remove the pipe at final abandonment. Sufficient data exists with certain pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, our intentions or the estimated economic life of the asset. Useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to allow us to reasonably estimate potential settlement dates and methods.

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO. Typically, we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for an ARO when assets are taken out of service or otherwise abandoned.

We did not record any additional ARO for the year ended December 31, 2013. We recorded an ARO of $0.4 million for the year ended December 31, 2012, when we recognized abandonment costs associated with assets we acquired through the September 2010 acquisition of the Elk City natural gas gathering and processing system. For the year ended December 31, 2011, no additional AROs were recorded. We recorded accretion expense of $0.2 million, $0.1 million and $0.1 million, respectively, in our consolidated statements of income for the years ended December 31, 2013, 2012 and 2011 for previously recorded asset retirement obligation liabilities.

We do not have any assets that are legally restricted for purposes of settling our ARO at December 31, 2013 and 2012. The following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for each of the years ended December 31, 2013 and 2012:

	2013	2012
	(in millions)	
Balance at beginning of period	$ 2.6	$2.1
Additions	—	0.4
Accretion expense	0.2	0.1
Balance at end of period	$ 2.8	$2.6

3. ACQUISITIONS AND DISPOSITIONS

We accounted for each of our completed acquisitions using the acquisition method and recorded the identifiable assets acquired and liabilities assumed at their acquisition-date fair values. We have included the results of operations from each of these acquisitions in our operating results from the acquisition date.

2011 Acquisitions

In May 2011, we acquired natural gas pipeline assets that are complementary to our existing East Texas system assets for a final purchase price of $26.7 million in cash.

4. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

We allocate our net income among our General Partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, to our limited partners, our General Partner and the holders of our incentive distribution rights, or IDRs, in accordance with the terms of our partnership agreement. We also allocate any earnings in excess of distributions to our limited partners, our General Partner and the holders of the IDRs in accordance with the terms of our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and our limited partners based on their respective proportionate ownership interests in us, after taking into account distributions to be paid with respect to the IDRs, as set forth in our partnership agreement.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to Limited Partners	Percentage Distributed to General Partner
Minimum Quarterly Distribution	Up to $0.3125	98 %	2 %
First Target Distribution	> $0.3125 to $0.359375	98 %	2 %
Second Target Distribution	> $0.359375 to $0.390625	85 %	15 %
Third Target Distribution	> $0.390625 to $0.468750	75 %	25 %
Over Third Target Distribution	In excess of $0.468750	50 %	50 %

We determined basic and diluted net income per limited partner unit as follows:

	For the year ended December 31,		
	2013[(3)]	2012[(3)]	2011[(3)]
	(in millions, except per unit amounts)		
Net income	$ 53.9	$167.5	$219.2
Less: Net income attributable to noncontrolling interest	33.7	102.2	133.7
Net income attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	20.2	65.3	85.5
Less distributions:			
Total distributable earnings to our General Partner	0.8	0.7	0.7
Total distributable earnings to our limited partners	36.5	33.4	33.4
Total distributable earnings	37.3	34.1	34.1
Underdistributed (Overdistributed) earnings	$(17.1)	$ 31.2	$ 51.4
Weighted average limited partner units outstanding	29.2	26.7	26.7
Basic and diluted earnings per unit:			
Distributed earnings per limited partner unit[(1)]	$ 1.25	$ 1.25	$ 1.25
Underdistributed (Overdistributed) earnings per limited partner unit[(2)]	(0.57)	1.15	1.89
Net income per limited partner unit (basic and diluted)	$ 0.68	$ 2.40	$ 3.14

(1) Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

(2) Represents the limited partners' share (98%) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and under distributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

(3) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% retained by EEP.

5. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $8.8 million at December 31, 2013 are included in "Accounts payable and other" on our consolidated statements of financial position. At December 31, 2013, we reclassed a book overdraft of $49.1 million to "Accounts payable and other" on our consolidated statements of financial position.

6. INVENTORY

Our inventory is comprised of the following:

	December 31,	
	2013	2012
	(in millions)	
Materials and supplies	$ 0.6	$ 0.4
Crude oil inventory	12.6	10.1
Natural gas and NGL inventory	74.8	64.3
	$88.0	$74.8

The "Cost of natural gas and natural gas liquids" on our consolidated statements of income includes charges totaling $3.4 million, $9.8 million and $3.6 million for the years ended December 31, 2013, 2012 and 2011, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and natural gas liquids, or NGLs, to reflect the current market value.

7. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment is comprised of the following:

	Depreciation Rates	December 31,	
		2013	2012
		(in millions)	
Land	—	$ 11.6	$ 8.7
Rights-of-way	2.08%—4.49%	380.0	340.3
Pipelines	1.89%—6.70%	1,741.9	1,603.8
Pumping equipment, buildings and tanks	1.48%—6.67%	79.2	65.4
Compressors, meters and other operating equipment	1.8%—20.0%	1,993.2	1,755.7
Vehicles, office furniture and equipment	2.19%—33.33%	148.5	133.0
Processing and treating plants	2.21%—2.73%	514.4	489.8
Construction in progress		181.4	402.2
Total property, plant and equipment		5,050.2	4,798.9
Accumulated depreciation		(967.9)	(835.9)
Property, plant and equipment, net		$4,082.3	$3,963.0

Based on our own internal study, with consideration of a third-party consultant's report, we revised depreciation rates for our Anadarko, North Texas and East Texas natural gas systems. These new depreciation rates were implemented effective July 1, 2011. The average remaining service life of these natural gas systems was extended from 29 years to 36 years. The predominant factor contributing to the change in service lives was an increase in the estimated remaining reserves in the regions our natural gas systems serve, due to enhancements in fracturing technologies which will allow producers to have greater access to unconventional gas. The new remaining service lives resulted in an approximately $34.0 million annual reduction in depreciation expense for the years ended 2013 and 2012, with a reduction of $17.0 million for the year ended 2011.

8. GOODWILL

Our goodwill originated from acquisitions by EEP that are fully associated with our gathering, processing and transportation business and our logistics and marketing business. For each of the years ended December 31, 2013 and 2012, the carrying amount of goodwill was $226.5 million consisting of $206.1 million and $20.4 million related to our gathering, processing and transportation and marketing and logistics businesses, respectively.

We test our goodwill for impairment annually primarily by using a discounted cash flow analysis. In addition, we also consider overall market capitalization of our business, cash flow measurement data and other factors. We completed our annual goodwill impairment test using amounts as of June 30, 2013, which did not indicate the existence of impairment to goodwill associated with any of our reporting units. Even if our estimate for the fair value of our assets had been reduced by 10% in our June 30, 2013 impairment testing, no impairment charge would have resulted. The critical assumptions used in our analysis included the following:

1) A weighted average cost of capital from 8%—9%;

2) An annual growth rate for our gathering, processing and transportation and logistics and marketing businesses of approximately 1.0% to 3.5%;

3) A capital structure consisting of approximately 50% debt and 50% equity; and

4) A long-term commodity price forecast using recent pricing information.

We did not identify or recognize any impairments to goodwill in connection with our annual testing of goodwill for impairment during the years ended December 31, 2013, 2012 and 2011. We have not observed any further events or circumstances subsequent to our analysis that would, more likely than not, reduce the fair value of our reporting units below the carrying amounts as of December 31, 2013.

9. INTANGIBLES

The following table provides the gross carrying value, accumulated amortization and activity affecting amounts comprising each of our major classes of intangible assets.

	Gross Carrying Amount				Accumulated Amortization				
	Natural Gas Intangibles				Natural Gas Intangibles				
	Natural Gas Opportunities	Customer Contracts	Other	Intangible Assets, Gross	Natural Gas Opportunities	Customers Contracts	Other	Accumulated Amortization Gross	Intangible Assets, Net
					(in millions)				
December 31, 2011	$291.0	$ 4.4	$11.9	$307.3	$(38.7)	$(0.6)	$(2.7)	$(42.0)	$265.3
Additions	—	—	3.5	3.5	—	—	—	—	3.5
Dispositions	—	—	—	—	—	—	—	—	—
Amortization	—	—	—	—	(10.3)	(0.6)	(0.7)	(11.6)	(11.6)
December 31, 2012	291.0	4.4	15.4	310.8	(49.0)	(1.2)	(3.4)	(53.6)	257.2
Additions	—	—	11.9	11.9	—	—	—	—	11.9
Dispositions	—	—	—	—	—	—	—	—	—
Amortization	—	—	—	—	(10.4)	(0.5)	(3.2)	(14.1)	(14.1)
December 31, 2013	$291.0	$ 4.4	$27.3	$322.7	$(59.4)	$(1.7)	(6.6)	$(67.7)	$255.0

Natural gas intangibles include customer contracts and natural gas supply opportunities. Our customer contracts are comprised entirely of natural gas purchase and sale agreements associated with our gathering, processing and transportation business and our logistics and marketing business. We amortize our customer contracts on a straight-line basis over the weighted average useful life of the underlying reserves at the time of acquisition, which is approximately 25 years.

We obtained a portion of the natural gas supply opportunities in conjunction with the 2003 North Texas system acquisition. We obtained an additional $189.2 million of natural gas supply opportunities in connection with our September 2010 acquisition of the Elk City system. The value of these intangible assets is derived from growth opportunities present in the Barnett Shale producing zone of North Texas and the Granite Wash reservoir of the Anadarko basin in western Oklahoma and the Texas Panhandle. The natural gas supply opportunities relate entirely to our gathering, processing and transportation business. We are amortizing the natural gas supply opportunities on a straight line basis over the weighted average estimated useful life of the underlying reserves at the time of the acquisition, which is approximate 25 to 30 years.

Our other intangible assets are comprised of contributions we made in aid of construction for our gathering, processing and transportation business. In connection with our October 2010 acquisition of a common carrier trucking company, we recognized $4.4 million of additional intangibles related to workforce contracts and customer relationships. We amortize our workforce contracts and customer relationships on a straight line basis over the weighted average estimated useful life of 3 years and the underlying reserves at the time of the acquisition up to 10 years, respectively.

We estimate the annual amortization expense associated with our intangibles to approximate $14.1 million per year until December 31, 2018.

10. DEBT

Credit Agreement

On November 13, 2013, in connection with the closing of the Offering, the Partnership, Midcoast Operating, and their material domestic subsidiaries, entered into a Credit Agreement (the "Credit Agreement"), by and among the Partnership, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, the material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially: (1) $90.0 million under the letter of credit facility; and (2) $75.0 million under the swing line facility. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility matures in three years, subject to four one-year requests for extensions. At December 31, 2013, we were in compliance with the terms of our financial covenants.

Loans under the Credit Agreement accrue interest at a per annum rate by reference, at the borrowers' election, to the Eurodollar rate, which is equal to the LIBOR rate or a comparable or successor rate reasonably approved by the Administrative Agent, or base rate, in each case, plus an applicable margin. The applicable margin on Eurodollar (LIBOR) rate loans ranges from 1.75% to 2.75% and the applicable margin on base rate loans ranges from 0.75% to 1.75%, in each case determined based upon our total leverage ratio (as defined below) at the applicable time. A letter of credit fee is payable by the borrowers' equal to the applicable margin for Eurodollar (LIBOR) rate loans times the daily amount available to be drawn under outstanding letters of credit. A commitment fee is payable by us equal to an applicable margin times the daily unused amount of the lenders' commitment, which applicable margin ranges from 0.30% to 0.50% based upon our total leverage ratio at the applicable time.

Each of our domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The credit facility is unsecured but security will be provided upon occurrence of any of the following: (1) for two consecutive quarters, the Total Leverage Ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (2) uncured breach to certain terms and conditions of the Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

Additionally, the Credit Agreement contains various covenants and restrictive provisions which limit the ability of the Partnership, Midcoast Operating and their subsidiaries to incur certain liens or permit them to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests during the continuance of a default, incur or guarantee additional debt, repay subordinated debt prior to maturity, make certain investments and acquisitions, alter their lines of business, enter into certain types of transactions with affiliates and enter into agreements that restrict their ability to perform certain obligations under the Credit Agreement or to make payments to a borrower or any of their material subsidiaries.

The Credit Agreement also requires compliance with two financial covenants. The Partnership must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio) of the Partnership and its consolidated subsidiaries (including Midcoast Operating), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. The Partnership also must maintain (on a consolidated basis), as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00.

These covenants are subject to exceptions and qualifications set forth in the Credit Agreement. At such time as the Partnership obtains an investment grade rating from either Moody's or S&P, certain covenants under the Credit Agreement will no longer be applicable to either the borrowers or the guarantors, or in some instances, any of them (including, but not limited to, the obligation to provide security in certain circumstances, certain restrictions on liens, investments and debt, and restrictions on dispositions).

The Credit Agreement also contains customary representations, warranties, indemnities and remedies provisions. In addition, the Credit Agreement contains events of default customary for transactions of this nature, including (1) the failure of either borrower to make payments required under the Credit Agreement; (2) the failure to comply with covenants and financial ratios in the Credit Agreement; (3) the occurrence of a change of control; (4) the institution of insolvency or similar proceedings against either borrower, a guarantor or a material subsidiary; and (5) the occurrence of a payment default, or the acceleration of payment, based on a non-payment default, under any other material indebtedness of either borrower or any of their subsidiaries. During the existence of an event of default, subject to the terms and conditions of the Credit Agreement, the lenders may terminate all outstanding commitments under the Credit Agreement and may declare any outstanding principal, together with accrued and unpaid interest, to be immediately due and payable and may require that all outstanding letters of credit be collateralized by cash.

Under the Credit Agreement, a change of control will be triggered if EEP or Enbridge ceases to control, directly or indirectly, our General Partner or if the general partner of Midcoast Operating ceases to be wholly owned, directly or indirectly, by the Partnership.

Working Capital Credit Facility

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a $250.0 million working capital credit facility with EEP as the lender. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility are scheduled to mature in 2017 and accrue interest at a per annum rate of the LIBOR, plus 2.5%. EEP's commitment to lend pursuant to the working capital credit facility will end on the earlier of the facility's maturity date (by acceleration or otherwise) and the date on which EEP owns less than 20% of the outstanding limited partner interests in Midcoast Operating. If EEP's commitment to lend has terminated before the facility has matured (by acceleration or otherwise), then the aggregate amount of all outstanding borrowings under the facility will automatically convert to a term loan that will bear interest at LIBOR (calculated as of the conversion date) plus 2.5%. Midcoast Operating has agreed to pay a commitment fee on the unused commitment at a per annum rate of 0.4250%, payable each fiscal quarter.

The working capital credit facility will contain customary events of default, including (1) the failure of Midcoast Operating to make payments required under the working capital credit facility or comply with the conditions of such working capital credit facility; (2) the failure of any of the representations or warranties of Midcoast Operating to be true in all material respects when made; (3) the occurrence of a change of control; (4) the institution of insolvency or similar proceedings against Midcoast Operating or us; and (5) the occurrence of a default under any other material indebtedness of Midcoast Operating or us. During the existence of an event of default, subject to the terms and conditions of the working capital credit facility, EEP may terminate its commitment and may declare any outstanding principal, together with accrued and unpaid interest, to be immediately due and payable. The working capital credit facility also contains certain customary representations, warranties, indemnities and remedies provisions and also provides that, if the Credit Agreement is secured, the working capital credit facility also will be secured to the same extent on a second lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the working capital credit facility and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Financial Support Agreement

On November 13, 2013, in connection with the closing of the Offering, Midcoast Operating entered into a Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP will provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party. Under the Financial Support Agreement, EEP's support of Midcoast Operating's and its wholly owned subsidiaries' obligations will terminate on the earlier to occur of (1) the fourth anniversary of the closing of the Offering and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in the Partnership), less than 20% of the total outstanding limited partner interest in Midcoast Operating.

The annual costs that Midcoast Operating initially estimates that it will incur under the Financial Support Agreement range from approximately $4.0 million to $5.0 million and are based on the cumulative average amount of letters of credit and guarantees that EEP will provide on Midcoast Operating's and its wholly owned subsidiaries' behalf multiplied by a 2.5% annual fee. The cumulative average amount of letters of credit and guarantees will be calculated (1) with respect to letters of credit, by reference to the aggregate face value, in U.S. dollars, of letters of credit outstanding at the close of business on any business day, after taking into account any changes in such amount since the close of business on the immediately preceding business day, and (2) with respect to guarantees, by reference to the net realizable financial obligation of Midcoast Operating and its wholly owned subsidiaries under the applicable contracts, in each case after taking into account market fluctuations in commodity prices, any related EEP letters of credit and any increases or decreases underlying each guarantee. The "net realizable financial obligation" is (1) in the case of outstanding commodity derivative contracts, the amount required to terminate or discharge each such contract based upon current market prices of the relevant commodity and (2) in the case of natural gas and NGL purchase agreements, the outstanding amount owed for product received that would be recorded as a liability under U.S. GAAP, in each case, net of any amounts owed to Midcoast Operating under any agreements with counterparties that have received guarantees from EEP. Based on the Partnership's 39% controlling interest in Midcoast Operating, the Partnership initially estimates that its proportionate share of these annual costs will range from $1.6 million to $2.0 million.

The Financial Support Agreement also provides that if the Credit Agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the Financial Support Agreement and liens, if secured, to the rights of the lenders under the Credit Agreement, subject to the terms and conditions of a subordination agreement.

Available Liquidity

The following table presents the primary components of our outstanding indebtedness with third parties and the weighted average interest rates associated with each component at the end of each period presented, before the effect of our interest rate hedging activities as discussed in, Note 14. *Derivative Financial Instruments and Hedging Activities*.

	(in millions)
Total credit available under Credit Agreement	$850.0
Less: Amounts outstanding under Credit Agreement	335.0
Total amount we could borrow at December 31, 2013	$515.0
Weighted average interest rate	2.5%

11. PARTNERS' CAPITAL

Prior to the Offering, partners' capital accounts were comprised of a 99.999% limited partner interest that was owned entirely by EEP and a 0.001% general partner interest that is owned by Midcoast OLP GP, L.L.C. (f/k/a Enbridge Midcoast Holdings, L.L.C.), or OLP GP, a wholly owned subsidiary of EEP. After the Offering, partners' capital accounts consist of general partner interests held by our General Partner, and limited partner interests held by EEP and the public. We paid cash distributions to EEP and OLP GP totaling $302.2 million and $342.4 million for the fiscal years ended December 31, 2012 and 2011, respectively, and $247.7 million for the portion of fiscal year 2013 prior to the Offering. No cash distributions were made to our partners in the period after the Offering through December 31, 2013.

Prior to the IPO, EEP also provided us with cash management services through a centralized treasury system. As a result, all of our charges and cost allocations covered by the centralized treasury system were deemed to have been paid by us to EEP, in cash, during the period in which the cost was recorded in the financial statements. In addition, all of our cash receipts were advanced to EEP as they were received. As a result of using EEP's centralized treasury system, the excess of cash receipts advanced to EEP over the charges and cash allocation is reflected as net cash distributions to partners in the statements of partners' capital.

12. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

Enbridge and its affiliates provide management, administrative, operational and workforce related services to us. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the administrative and operational services charged to us.

We do not directly employ any of the individuals responsible for managing or operating our business. We have historically obtained managerial, administrative and operational services from EEP's general partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, EEP, Enbridge Management and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse EEP's general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us. In connection with the Offering, we entered into an intercorporate services agreement with EEP pursuant to which we agreed upon certain aspects of our relationship with EEP, including the provision by EEP or its affiliates to us of certain administrative services and employees, our agreement to reimburse EEP or its affiliates for the cost of such services and employees and certain other matters.

Intercorporate Service Agreements

On November 13, 2013, in connection with the closing of the Offering, the Partnership entered into an Intercorporate Service Agreement with EEP, pursuant to which EEP will provide the Partnership with the following services:

- executive, management, business development, administrative, legal, human resources, records and information management, public affairs, investor relations, government relations and computer support services;
- accounting and tax planning and compliance services, including preparation of financial statements and income tax returns, unitholder tax reporting and audit and treasury services;
- strategic insurance advice, planning and claims management and related support services, and arrangement of insurance coverage as required;
- facilitation of capital markets access and financing services, cash management and related banking services financial structuring and advisory services, as well as credit support for the Partnership's subsidiaries and affiliates on an as-needed basis for projects, transactions or other purposes;
- operational and technical services, including integrity, safety, environmental, project management, engineering, fundamentals analysis and regulatory, and pipeline control and field operations; and
- such other services as the Partnership may request.

Under the Intercorporate Services Agreement, the Partnership will reimburse EEP and its affiliates for the costs and expenses incurred in providing such services to the Partnership. The allocation methodology under which the Partnership will reimburse EEP and its affiliates for the provision of general administrative and operational services to Midcoast Operating will not differ from what Midcoast Operating was allocated historically under its prior services agreements with Enbridge and certain of its affiliates that were in effect prior to the Intercorporate Services Agreement. However, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually. Based on the Partnership's 39% interest in Midcoast Operating, the reduction in amounts payable for general and administrative services attributable to the Partnership will be approximately $9.8 million annually and will continue for the term of the agreement.

The total amount incurred by us, through EEP, per the MEP only cost centers, for services received pursuant to the general and administrative services agreement for the years ended December 31, 2013, 2012 and 2011 was $176.9 million, $207.3 million and $182.1 million, respectively. These amounts were settled through "Net cash contributions from partners" as reflected on our Consolidated Statements of Partners' Capital and amounts settled after November 12, 2013 were settled through cash. The following table presents the affiliate amounts reflected in our Consolidated Statements of Income by category as follows:

	December 31,		
	2013	**2012**	**2011**
		(in millions)	
Operating and maintenance—affiliate	$ 78.7	$110.1	$100.5
General and administrative—affiliate	98.2	97.2	81.6
Total	$176.9	$207.3	$182.1

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of $6.8 million, $6.4 million and $6.0 million as of December 31, 2013, 2012 and 2011, respectively, that we recorded as additions to "Property, plant and equipment, net" on our consolidated statements of financial position.

Insurance Allocation Agreement

We participate in the comprehensive insurance program that is maintained by Enbridge for its benefit and the benefit of its subsidiaries. On November 13, 2013, in connection with the closing of the Offering, we entered into an Amended and Restated Allocation Agreement, or the Insurance Allocation Agreement, by and among the Partnership, Enbridge, EEP and Enbridge Income Fund Holdings Inc., in order to participate in the comprehensive insurance program that is maintained by Enbridge for it and its subsidiaries. Under this agreement, in the unlikely event that multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis.

Affiliate Revenues and Purchases

We purchase natural gas, NGLs and crude oil from third parties, which subsequently generate operating revenues from sales to Enbridge and its affiliates. The sales to Enbridge and its affiliates are presented in "Operating revenue - affiliate" on our consolidated statements of income. These transactions are entered into at the market price on the date of sale. Included in our results for the years ended December 31, 2013, 2012 and 2011 are operating revenues from sales to Enbridge and its affiliates of $213.1 million, $396.2 million and $323.0 million, respectively.

We also purchase natural gas, NGLs and crude oil from Enbridge and its affiliates for sale to third parties at market prices on the date of purchase. The purchases of natural gas, NGLs and crude oil from Enbridge and its affiliates are presented in "Cost of natural gas and natural gas liquids - affiliate" on our consolidated statements of income. Included in our results for the years ended December 31, 2013, 2012 and 2011 are costs for natural gas, NGLs and crude oil purchases from Enbridge and its affiliates of $119.6 million, $289.5 million and $202.0 million, respectively.

Routine purchases and sales with affiliates are settled monthly through our treasury function at terms that are consistent with third-party transactions. Routine purchases and sales with affiliates that have not yet been settled are included in "Due from general partner and affiliates" and "Due to general partner and affiliates" on our consolidated statements of financial position.

Related Party Transactions with Joint Venture

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together are constructing a 580 mile NGL intrastate transportation pipeline and a related NGL gathering system that was placed into service in the fourth quarter of 2013. Our equity investment in the Texas Express NGL system at December 31, 2013, 2012 and 2011 was $371.3 million, $183.7 million and $10.7 million, respectively, which is included on our consolidated statements of financial position in "Equity investment in joint venture."

Our logistics and marketing business has made commitments to transport up to 120,000 barrels per day, or bpd, of NGLs on the Texas Express NGL system from 2013 to 2023.

Partners' Capital Transactions

Prior to the Offering, our capital accounts were comprised of a 99.999% limited partner interest that was owned entirely by EEP and a 0.001% general partner interest that was owned by the Midcoast OLP GP, L.L.C (f/k/a Enbridge Midcoast Holdings, L.L.C.), or the OLP GP, a wholly owned subsidiary of EEP. After the Offering, partners' capital accounts consist of general partner interests held by our General Partner, and limited partner interests held by EEP and the public. We paid cash distributions to EEP and OLP GP totaling $302.2 million and $342.4 million for the fiscal years ended December 31, 2012 and 2011, respectively, and $247.7 million for the portion of fiscal year 2013 prior to the Offering. No cash distributions were made to our partners in the period after the Offering through December 31, 2013. These amounts were settled through "Distributions to partners" as reflected on our consolidated statements of cash flows.

Conflicts of Interest

Under our partnership agreement, our General Partner has a duty to manage us in a manner it believes is in the best interests of the Partnership. However, because our General Partner is a wholly owned subsidiary of EEP, the officers and directors of our General Partner also have a duty to manage the business of our General Partner in a manner that they believe is in the best interests of EEP. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our General Partner and its affiliates, including EEP, on the other hand. In addition, our General Partner may determine to manage our business in a way that directly benefits EEP's businesses, rather than indirectly benefitting EEP solely through its ownership interests in us. All of these actions are permitted under our partnership agreement and will not be a breach of any duty (fiduciary or otherwise) of our General Partner. As permitted by Delaware law, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our General Partner with contractual standards governing the duties of the General Partner and contractual methods of resolving conflicts of interest. The effect of these provisions is to restrict the remedies available to our unitholders for actions that might otherwise constitute breaches of our General Partner's fiduciary duties. Our partnership agreement also provides that affiliates of our General Partner, including EEP and Enbridge, are not restricted from competing with us, and neither our General Partner nor its affiliates have any obligation to present business opportunities to us.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013 and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. The Receivables Agreement and the transactions contemplated thereby were approved by a special committee of the board of directors of Enbridge Management, which prior to the Offering, effectively managed the business of the Predecessor through its management of EEP's business. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of those of ours subsidiaries and other subsidiaries of EEP that are parties thereto up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement. EEP and the Partnership each act in an administrative capacity as collection agent on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. Prior to the amendment to the Receivables Agreement on December 2, 2013 EEP was the sole collection agent on behalf of the Enbridge subsidiary. EEP and the Partnership have no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative—affiliate" expense in our consolidated statements of income. For the year ended December 31, 2013, the loss stemming from the discount on the receivables sold was not material. For the year ended December 31, 2013, we derecognized and sold $1,566.7 million, of accrued receivables to the Enbridge subsidiary. For the year ended December 31, 2013, the cash proceeds were $1,566.3 million, which was remitted to EEP or the Partnership, as applicable, in their capacity as collection agent, through our centralized treasury system. As of December 31, 2013, $273.6 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

	December 31,		
	2013	2012	2011
		(millions)	
Interest cost incurred	$20.2	$11.9	$ 3.3
Interest capitalized	18.5	11.9	3.3
Interest expense	$ 1.7	$ —	$—
Interest cost paid	$20.2	$11.9	$ 3.3

Derivative Transactions

We have related party derivative transactions executed on behalf of EEP that were contracted through the Partnership prior to the Offering and are allocated to EEP. These transactions were contracted to hedge the forward price of EEP's crude oil length inherent to the operation of pipelines and to hedge EEP's interest payments of variable rate debt obligations that are sensitive to changes in interest rates. These hedges create a fixed sales price for crude oil that EEP will receive in the future and lock in the interest rate on EEP's anticipated future debt. Subsequent to the Offering, these transactions were re-contracted through EEP and will no longer be allocated from the Partnership. These transactions are included as part of Note 14. *Derivative Financial Instruments and Hedging Activities.*

13. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to the operating activities of our gathering, processing, and transportation and logistics and marketing businesses, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or otherwise, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our gathering, processing and transportation and logistics and marketing businesses. We continue to voluntarily monitor past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations.

As of December 31, 2013, we did not record any environmental liabilities, as compared to $0.1 million in 2012, included in "Other long-term liabilities," on our consolidated statements of financial position for costs we have incurred primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our natural gas assets and penalties we have been or expect to be assessed related to environmental liabilities.

Natural Gas in Custody

Approximately 40% to 50% of the natural gas volumes handled by our gathering, processing and transportation business are transported for customers on a contractual basis. We purchase the remaining volumes and sell to third parties downstream of the purchase point. At any point in time, the value of our customers' natural gas in the custody of our gathering, processing and transportation assets is not significant to our operating results, cash flows, or financial position.

Rights-of-Way

As part of our pipeline construction process, we must obtain certain rights-of-way from landowners whose property the pipeline will cross. Rights-of-way that we buy are capitalized as part of "Property, plant and equipment, net" in our consolidated statements of financial position. Rights-of-way that we lease are expensed. We have recorded expenses of $0.3 million, $0.9 million and $0.6 million for the leased right-of-way agreements for the years ended December 31, 2013, 2012, and 2011, respectively.

Legal and Regulatory Proceedings

We are a participant in a number of legal proceedings arising in the ordinary course of business. Some of these proceedings are not covered, in whole or in part, by insurance. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial position, results of operations or cash flows. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Future Minimum Commitments

As of December 31, 2013, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

	2014	2015	2016	2017	2018	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$120.7	$ —	$ —	$ —	$ —	$ —	$ 120.7
Other operating leases	24.6	24.3	23.7	22.7	15.5	91.1	201.9
Right-of-way[2]	0.6	0.3	0.4	0.1	0.1	2.2	3.7
Product purchase obligations[3]	24.5	17.7	8.8	15.7	26.1	147.1	239.9
Transportation/Service contract obligations[4]	46.0	46.7	44.9	88.8	99.1	513.2	838.7
Fractionation agreement obligations[5]	63.3	63.3	63.3	63.3	63.3	276.6	593.1
Total	$279.7	$152.3	$141.1	$190.6	$204.1	$1,030.2	$1,998.0

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our growth projects.

(2) Right-of-way payments are estimated to approximate $0.1 million to $0.6 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2018.

(3) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at prices approximating market at the time of delivery.

(4) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

(5) The fractionation agreement obligations represent the minimum payment amounts for firm fractionation of our NGL supply that we reserve at third party fractionation facilities.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with commodity price risks through 2016 in accordance with our risk management policies.

Accounting Treatment

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply a mid-market pricing convention, which we refer to as the market approach, to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimates of fair value.

In accordance with the applicable authoritative accounting guidance, if a derivative financial instrument does not qualify as a cash flow hedge, or is not designated as a cash flow hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in "cost of natural gas and natural gas liquids" or "operating revenue" for our commodity-based derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in "Accumulated other comprehensive income," also referred to as AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement until the underlying transaction occurs. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in "cost of natural gas and natural gas liquids" for commodity hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have derivative financial instruments associated with our commodity activities where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "cost of natural gas and natural gas liquids" or "operating revenue" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to volatility in our earnings and in our cash flows upon settlement:

Commodity Price Exposures:

- **Transportation**—In our logistics and marketing business, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.
- **Storage**—In our logistics and marketing business, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the natural gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas or NGLs are recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas and NGL storage activities can increase volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **Optional Natural Gas Processing Volumes**—In our gathering, processing and transportation business, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL Forward Contracts**—In our logistics and marketing business, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. A sub-group of physical NGL sales contracts qualify for the normal purchases and normal sales, or NPNS, scope exception. All other forward contracts are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.
- **Natural Gas Forward Contracts**—In our logistics and marketing business, we use forward contracts to sell natural gas to our customers. Certain physical natural gas contracts with terms allowing for

economic net settlement are being marked to market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.

- **Crude Forward Contracts—**In our logistics and marketing business, we use forward contracts to fix the price of crude we purchase and store in inventory and to fix the price of crude that we sell from inventory. A sub-group of physical crude contracts with terms allowing for economic net settlement do not qualify for the NPNS, scope exception and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in crude prices until the forward contracts are settled.
- **Natural Gas and NGL Options**—In our gathering, processing and transportation business, we use options to hedge the forecasted commodity exposure of our NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to volatility due to movements in the prices of NGLs and natural gas until the underlying long-term transactions are settled.

In all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical cost or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31,	
	2013	2012
	(in millions)	
Other current assets and Due from General Partner and affiliates	$ 10.3	$ 275.0
Other assets, net	10.3	78.1
Accounts payable and other and Due to General Partner and affiliates	(21.1)	(259.9)
Other long-term liabilities	(0.9)	(78.0)
	$ (1.4)	$ 15.2

The changes in the net assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $0.7 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the years ended December 31, 2013 and 2012, commodity hedge gains of

$1.7 million and losses of $6.3 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $10.5 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2013, will be reclassified from AOCI to earnings during the next 12 months.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	December 31,	
	2013	2012
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ 0.2	$ —
AA	(2.1)	(116.6)
A	(1.1)	(150.4)
Lower than A	1.6	282.2
	$(1.4)	$ 15.2

(1) As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. As of December 31, 2013 and December 31, 2012, we were not holding any cash collateral on our asset exposures. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At December 31, 2013 and 2012, we had credit concentrations in the following industry sectors, as presented below:

	December 31, 2013	December 31, 2012
	(in millions)	
United States financial institutions and investment banking entities	$ 2.4	$(204.7)
Non-United States financial institutions	0.1	(87.4)
Integrated oil companies	(1.6)	4.5
General Partner and affiliates	(0.1)	297.2
Other	(2.2)	5.6
	$(1.4)	$ 15.2

Gross derivative balances are presented below before the effects of collateral received or posted and without the effects of master netting arrangements. Both our assets and liabilities are adjusted for non-performance risk, which is statistically derived. This credit valuation adjustment model considers existing derivative asset and liability balances in conjunction with contractual netting and collateral arrangements, current market data such as credit default swap rates and bond spreads and probability of default assumptions to quantify an adjustment to fair value. For credit modeling purposes, collateral received is included in the calculation of our assets, while any collateral posted is excluded from the calculation of the credit adjustment. Our credit exposure for these over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. A reconciliation between the derivative balances presented at gross values rather than the net amounts we present in our other derivative disclosures, is also provided below.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Financial Position Location	Asset Derivatives Fair Value at December 31, 2013	2012[3]	Liability Derivatives Fair Value at December 31, 2013	2012[3]
		(in millions)			
Derivatives designated as hedging instruments[1]					
Commodity contracts	Other current assets	$ 2.0	$ 12.2	$ (0.6)	$ (4.2)
Commodity contracts	Other assets	3.5	2.5	(0.5)	(1.1)
Commodity contracts	Accounts payable and other	1.9	4.7	(12.7)	(5.7)
Commodity contracts	Other long-term liabilities	0.6	2.0	(1.4)	(4.5)
		8.0	21.4	(15.2)	(15.5)
Derivatives not designated as hedging instruments					
Interest rate contracts	Other current assets[2]	$ —	$246.9	$ —	$ —
Interest rate contracts	Other assets[2]	—	68.3	—	(3.3)
Interest rate contracts	Accounts payable and other[2]	—	—	—	(246.9)
Interest rate contracts	Other long-term liabilities[2]	—	3.3	—	(68.3)
Commodity contracts	Other current assets[2]	9.0	27.2	(0.1)	(7.1)
Commodity contracts	Other assets[2]	10.7	11.8	(3.4)	(0.1)
Commodity contracts	Accounts payable and other[2]	5.4	0.8	(15.6)	(12.8)
Commodity contracts	Other long-term liabilities[2]	—	1.6	(0.2)	(12.1)
		25.1	359.9	(19.3)	(350.6)
Total derivative instruments		$33.1	$381.3	$(34.5)	$(366.1)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.

(2) Includes both affiliate and third party transactions.

(3) The effect of derivative instruments on the consolidated statements of financial position, as of December 31, 2012, was revised to disclose the financial position location on a gross basis. The revisions to the disclosures are not considered material to and had no impact on amounts previously reported in the consolidated statements of financial position.

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)(1)	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)(1)
		(in millions)			
For the year ended December 31, 2013					
Commodity contracts . . .	$(16.5)	Cost of natural gas and natural gas liquids	$ 2.7	Cost of natural gas and natural gas liquids	$ 3.3
Total	$(16.5)		$ 2.7		$ 3.3
For the year ended December 31, 2012					
Commodity contracts . . .	$ 41.8	Cost of natural gas and natural gas liquids	$ 0.1	Cost of natural gas and natural gas liquids	$ 3.1
Total	$ 41.8		$ 0.1		$ 3.1
For the year ended December 31, 2011					
Commodity contracts . . .	$ 17.7	Cost of natural gas and natural gas liquids	$(59.3)	Cost of natural gas and natural gas liquids	$(5.3)
Total	$ 17.7		$(59.3)		$(5.3)

(1) Includes only the ineffective portion of derivatives that are designated as hedging instruments and does not include net gains or losses associated with derivatives that do not qualify for hedge accounting treatment.

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges
	(in millions)
Balance at December 31, 2012	$ 7.1
Other Comprehensive Income before reclassifications	(7.6)
Amounts reclassified from AOCI(1)	(2.7)
Tax benefit (expense)	0.1
Net other comprehensive income	$(10.2)
Balance at December 31, 2013	$ (3.1)

(1) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

Reclassifications from Accumulated Other Comprehensive Income

	December 31,		
	2013	2012	2011
	(in millions)		
Losses (gains) on cash flow hedges:			
Commodity Contracts[1]	$(2.7)	$(0.1)	$59.3
Total Reclassifications from AOCI	$(2.7)	$(0.1)	$59.3

(1) Loss (gain) reported within Cost of natural gas and natural gas liquids in the consolidated statements of income.

Effect of Derivative Instruments on Consolidated Statements of Income

		December 31,		
		2013	2012[4]	2011[4]
Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings[2]	Amount of Gain or (Loss) Recognized in Earnings[1]		
		(in millions)		
Commodity contracts	Operating revenue	$ (3.0)	$ —	$ —
Commodity contracts	Cost of natural gas and natural gas liquids[3]	(7.9)	19.5	(21.3)
Total		$(10.9)	$19.5	$(21.3)

(1) Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.

(2) Does not include settlements associated with derivative instruments that settle through physical delivery.

(3) Includes settlement losses of $4.6 million, settlement gains of $21.4 million, and settlement losses of $43.1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(4) The effects of derivative instruments on consolidated statements of income have been revised to include settlement on derivatives not designated as hedge instruments of a gain of $21.4 million and a loss of $43.1 million for the years ended December 31, 2012 and 2011, respectively. This revision to the disclosure had not impact on previously reported net income or earnings per unit.

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	December 31, 2013			December 31, 2012		
	Assets	Liabilities	Total	Assets	Liabilities	Total
	(in millions)					
Fair value of derivatives—gross presentation	$ 33.1	$(34.5)	$(1.4)	$381.3	$(366.1)	$15.2
Effects of netting agreements	(12.5)	12.5	—	(28.2)	28.2	—
Fair value of derivatives—net presentation	$ 20.6	$(22.0)	$(1.4)	$353.1	$(337.9)	$15.2

We record the fair market value of our derivative financial and physical instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a net basis by counterparty. The terms of the ISDA, which governs our financial contracts and our other master netting agreements, allow the parties to elect in respect of all transactions under the agreement, in the event of a default and upon notice to the defaulting party, for the non-defaulting party to set-off all settlement payments, collateral held and any other obligations (whether or not then due), which the non-defaulting party owes to the defaulting party.

Offsetting of Financial Assets and Derivative Assets

	As of December 31, 2013				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$33.1	$(12.5)	$20.6	$(1.9)	$18.7
Total	$33.1	$(12.5)	$20.6	$(1.9)	$18.7

Offsetting of Financial Liabilities and Derivative Liabilities

	As of December 31, 2013				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$(34.5)	$12.5	$(22.0)	$1.9	$(20.1)
Total	$(34.5)	$12.5	$(22.0)	$1.9	$(20.1)

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012. We classify financial assets and liabilities 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 our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	December 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Commodity contracts:								
Financial	$—	$(3.4)	$(6.9)	(10.3)	$—	$(7.0)	$ 8.4	$ 1.4
Physical	—	—	0.5	0.5	—	—	7.4	7.4
Commodity options	—	—	8.4	8.4	—	—	6.4	6.4
Total	$—	$(3.4)	$ 2.0	$ (1.4)	$—	$(7.0)	$22.2	$15.2

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs, and Crude) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013[(2)]	Valuation Technique	Unobservable Input	Range[(1)] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$(0.0)	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	$(6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	$(0.5)	Market Approach	Forward Crude Price	86.37	103.04	97.24	Bbl
NGLs	$(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 2.0						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.1 million of gains.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2012[(2)]	Valuation Technique	Unobservable Input	Range[(1)] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$ 8.8	Market Approach	Forward Gas Price	3.21	4.31	3.54	MMBtu
NGLs	$ (0.4)	Market Approach	Forward NGL Price	0.25	2.21	1.40	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.7	Market Approach	Forward Gas Price	3.19	4.58	3.73	MMBtu
Crude Oil	$ 2.6	Market Approach	Forward Crude Price	65.22	116.56	94.31	Bbl
NGLs	$ 3.1	Market Approach	Forward NGL Price	—	2.22	0.61	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 6.4	Option Model	Option Volatility	29%	104%	40%	
Total Fair Value	$22.2						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.

(2) Fair values are presented in millions and include credit valuation adjustments of approximately $0.1 million of losses.

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2013 to December 31, 2013. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
		(in millions)		
Beginning balance as of January 1, 2013	$ 8.4	$ 7.4	$ 6.4	$ 22.2
Transfers out of Level 3[1]	—	—	—	—
Gains or losses				
Included in earnings	(0.8)	22.1	(3.2)	18.1
Included in other comprehensive income	(3.8)	—	—	(3.8)
Purchases, issuances, sales and settlements:				
Purchases	—	—	7.5	7.5
Settlements[2]	(10.7)	(29.0)	(2.3)	(42.0)
Ending balance as of December 31, 2013	$ (6.9)	$ 0.5	$ 8.4	$ 2.0
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$ (5.7)	$ (0.4)	$ 7.1	$ 1.0
Amounts reported in operating revenue	$ —	$ (3.0)	$ —	$ (3.0)

(1) Our policy is to recognize transfers as of the last day of the reporting period.

(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair value of expected cash flows of our outstanding commodity based swaps and physical contracts at December 31, 2013 and 2012.

	At December 31, 2013						At December 31, 2012	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	536,870	$ 4.26	$ 4.27	$—	$ —	$—	$—
	NGL	631,250	$69.29	$68.99	$ 0.6	$ (0.4)	$—	$—
	Crude Oil	—	$ —	$ —	$—	$ —	$—	$(5.0)
Receive fixed/pay variable	Natural Gas	4,478,991	$ 3.94	$ 4.14	$ 0.1	$ (1.0)	$ 0.2	$—
	NGL	2,659,300	$54.80	$57.77	$ 4.8	$(12.7)	$ 0.9	$(2.7)
	Crude Oil	1,066,950	$90.85	$95.71	$ 0.3	$ (5.4)	$ 5.4	$(2.7)
Receive variable/pay variable	Natural Gas	32,752,500	$ 4.12	$ 4.11	$ 0.6	$ (0.1)	$ 0.1	$(0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,083,450	$47.81	$47.77	$ 0.9	$ (0.9)	$—	$—
	Crude Oil	50,700	$98.47	$98.10	$—	$ —	$—	$—
Receive fixed/pay variable	NGL	1,335,534	$46.80	$48.44	$ 0.4	$ (2.6)	$—	$—
	Crude Oil	165,200	$96.08	$98.48	$—	$ (0.4)	$—	$—
Receive variable/pay variable	Natural Gas	41,064,012	$ 4.21	$ 4.20	$ 0.9	$ (0.4)	$ 0.5	$—
	NGL	9,337,617	$40.45	$40.23	$ 5.8	$ (3.7)	$—	$—
	Crude Oil	998,423	$97.16	$97.33	$ 1.1	$ (1.2)	$—	$—
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	565,750	$51.33	$50.56	$ 1.5	$ (1.1)	$ 0.7	$(0.2)
	Crude Oil	350,400	$93.00	$88.07	$ 1.7	$ —	$ 6.8	$(0.2)
Receive variable/pay variable	Natural Gas	4,707,500	$ 4.02	$ 4.01	$ 0.1	$ —	$—	$—
Receive variable/pay fixed	Crude Oil	—	$ —	$ —	$—	$ —	$—	$(5.6)
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,802,925	$ 4.19	$ 4.14	$ 0.5	$ (0.1)	$ 0.4	$—
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$99.31	$83.41	$ 0.7	$ —	$ 0.5	$—
Physical Contracts								
Receive variable/pay variable	Natural Gas	996,740	$ 4.23	$ 4.13	$ 0.1	$ —	$ 0.1	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2013 and December 31, 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of gains at December 31, 2013 and $0.2 million of losses at December 31, 2012.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2013 and 2012.

	At December 31, 2013						At December 31, 2012	
					Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Strike Price(2)	Market Price(2)	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2014								
Puts (purchased)	Natural Gas	1,825,000	$ 3.90	$ 4.19	$ 0.2	$—	$—	$—
	NGL	493,500	$51.91	$53.47	$ 2.9	$—	$ 1.3	$—
Calls (written)	NGL	273,750	$57.93	$53.35	$—	$(1.0)	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.14	$ 1.7	$—	$—	$—
	NGL	930,750	$53.57	$55.13	$ 6.0	$—	$—	$—
	Crude Oil	273,750	$85.00	$87.74	$ 1.8	$—	$—	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.14	$—	$(0.3)	$—	$—
	NGL	109,500	$81.90	$81.24	$—	$(1.0)	$—	$—
	Crude Oil	273,750	$90.25	$87.74	$—	$(1.9)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2013 and 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

15. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the state of Texas that is based upon many but not all items included in net income. We report these taxes as income taxes as set forth in the authoritative accounting guidance.

Our income tax expense is $8.3 million, $3.8 million and $2.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. We computed our income tax expense by applying a Texas state income tax rate to modified gross margin. The Texas state income tax rate was 0.5% for the years ended December 31, 2013, 2012 and 2011. Our income tax expense represents effective tax rates as applied to pretax book income of 13.3%, 2.1% and 1.3% for December 31, 2013, 2012 and 2011, respectively. The effective tax rate for the Partnership is calculated by dividing the income tax expense by the pretax net book income or loss. The income base for calculating income tax expense is modified gross margin for Texas rather than net book income or loss.

At December 31, 2013 and 2012, we have included a current income tax payable of $1.0 million and $3.7 million in "Property and other taxes payable," respectively. In addition, at December 31, 2013 and December 31, 2012, we have included a deferred income tax liability of $11.1 million and $3.0 million, respectively, in "Other long-term liabilities," on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting. Included in the $11.1 million is $6.0 million due to a new tax bill that went into effect in June 2013, as discussed below.

The Texas Legislature passed House Bill 500, or HB 500, and it was subsequently signed into law in June 2013. The most noteworthy item in the law for us is that HB 500 allows a pipeline company that transports oil, gas, or other petroleum products owned by others to subtract as cost of goods sold, or COGS, its depreciation, operations and maintenance costs related to the services provided. Under the new law, we are allowed additional deductions against our income for Texas margin tax purposes. We have recorded an additional "Deferred income tax liability" on our consolidated statements of financial position of approximately $6.0 million for the year ended December 31, 2013 as a result of this new tax law. In the future, our effective tax rate in the State of Texas will be lower as a result of this change in law.

For the years ended December 31, 2013, 2012 and 2011, we paid $2.5 million, $2.8 million and $2.5 million in income taxes, respectively.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment. The tax effects of significant temporary differences representing deferred tax assets and liabilities are as follows:

	December 31,	
	2013	2012
	(in millions)	
Net book basis of assets in excess of tax basis	$(11.2)	$(3.0)
Net book losses on derivatives not recognized for tax purposes	0.1	—
Net deferred tax liability	$(11.1)	$(3.0)

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ended December 31, 2012, 2011, and 2010.

Accounting for Uncertainty in Income Taxes

For the years ended December 31, 2013, 2012 and 2011, respectively, we have not recorded any amounts for uncertain tax positions.

16. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker, collectively comprised of our senior management, in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that are managed separately, since each business segment requires different operating strategies. We conduct our business through two distinct reporting segments: gathering, processing and transportation and logistics and marketing.

The following tables present certain financial information relating to our business segments and corporate activities:

	As of and for the year ended December 31, 2013			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$2,689.8	$4,963.7	$ —	$7,653.5
Less: Intersegment revenue	1,960.8	99.1	—	2,059.9
Operating revenue	729.0	4,864.6	—	5,593.6
Cost of natural gas and natural gas liquids	157.6	4,779.5	—	4,937.1
Segment gross margin	571.4	85.1	—	656.5
Operating and maintenance	278.9	71.4	—	350.3
General and administrative	86.6	11.6	—	98.2
Depreciation and amortization	135.7	7.2	—	142.9
	501.2	90.2	—	591.4
Operating income (loss)	70.2	(5.1)	—	65.1
Other income (expense)[3]	(1.5)	—	0.3	(1.2)
Interest expense	—	—	1.7	1.7
Income (loss) before income tax expense	68.7	(5.1)	(1.4)	62.2
Income tax expense	—	—	8.3	8.3
Net income (loss)	68.7	(5.1)	(9.7)	53.9
Less: Net income attributable to: noncontrolling interest	—	—	(0.6)	(0.6)
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 68.7	$ (5.1)	$ (9.1)	$ 54.5
Total assets[2]	$4,962.1	$ 591.4	$482.9	$6,036.4
Capital expenditures (excluding acquisitions)	$ 233.8	$ 17.5	$ 18.8	$ 270.1

(1) Corporate consists of interest expense, interest income, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Totals assets for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

(3) Other income (expense) for our Gathering, Processing and Transportation segment includes a loss of $1.0 million from our equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

	As of and for the year ended December 31, 2012			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$2,716.9	$4,640.8	$ —	$7,357.7
Less: Intersegment revenue	1,898.9	100.9	—	1,999.8
Operating revenue	818.0	4,539.9	—	5,357.9
Cost of natural gas and natural gas liquids	131.2	4,452.9	—	4,584.1
Segment gross margin	686.8	87.0	—	773.8
Operating and maintenance	281.5	80.8	—	362.3
General and administrative	85.8	19.1	0.2	105.1
Depreciation and amortization	128.0	7.0	—	135.0
	495.3	106.9	0.2	602.4
Operating income (loss)	191.5	(19.9)	(0.2)	171.4
Other expense	—	—	(0.1)	(0.1)
Income (loss) before income tax expense	191.5	(19.9)	(0.3)	171.3
Income tax expense	—	—	3.8	3.8
Net income (loss)	$ 191.5	$ (19.9)	$ (4.1)	$ 167.5
Total assets[2]	$4,609.0	$1,011.8	$46.6	$5,667.4
Capital expenditures (excluding acquisitions)	$ 443.6	$ 9.0	$ —	$ 452.6

(1) Corporate consists of interest expense, interest income, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Total assets for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

	As of and for the year ended December 31, 2011			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in Millions)			
Total revenue	$3,539.0	$6,984.4	$ —	$10,523.4
Less: Intersegment revenue	2,624.8	70.4	—	2,695.2
Operating revenue	914.2	6,914.0	—	7,828.2
Cost of natural gas	271.1	6,795.5	—	7,066.6
Segment gross margin	643.1	118.5	—	761.6
Operating and maintenance	241.0	76.8	—	317.8
General and administrative	71.6	10.1	0.1	81.8
Depreciation and amortization	135.2	7.5	—	142.7
	447.8	94.4	0.1	542.3
Operating income (loss)	195.3	24.1	(0.1)	219.3
Other income	—	—	2.8	2.8
Income before income tax expense	195.3	24.1	2.7	222.1
Income tax expense	—	—	2.9	2.9
Net income (loss)	$ 195.3	$ 24.1	$ (0.2)	$ 219.2
Total assets[2]	$4,155.6	$ 922.2	$56.8	$ 5,134.6
Capital expenditures (excluding acquisitions)	$ 432.4	$ 10.2	$ —	$ 442.6

(1) Corporate consists of interest expense, interest income, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Total assets for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

17. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for the item labeled "Other" in the "Cash from operating activities" section our consolidated statements of cash flows.

	December 31,		
	2013	2012	2011
	(in millions)		
Texas Express Long-term inventory (line fill)	$(9.5)	$—	$—
Amortization of insurance premiums	9.2	—	—
Loss on sale of assets	1.1	—	—
Equity loss from investment in Texas Express NGL system	1.0	—	—
Amortization of hedges	0.4	3.6	8.5
Allowance for interest used during construction	—	(4.5)	—
Write-down of project costs	—	4.3	—
Gain on sale of assets	—	—	(1.5)
Allowance for doubtful accounts	(0.4)	(0.2)	0.4
Other	(0.5)	0.3	1.4
	$ 1.3	$ 3.5	$ 8.8

In the “Cash used in investing activities” section of the consolidated statements of cash flows, we exclude changes that did not affect cash. The following is a reconciliation of additions to property, plant and equipment to total capital expenditures (excluding “Investment in joint venture”):

	For the year ended December 31,		
	2013	2012	2011
	(in millions)		
Additions to property, plant and equipment	$273.4	$451.7	$441.5
Increase (decrease) in construction payables	(3.3)	0.9	1.1
Total capital expenditures (excluding “Investment in joint venture”)	$270.1	$452.6	$442.6

18. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-04 which provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Presentation of Unrecognized Tax Benefits

In July 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-11 which requires the presentation of unrecognized tax benefit as a reduction to a deferred tax asset for a net operating loss carry forward unless specific conditions exist. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied prospectively. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

19. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
	(in millions, except per unit amounts)				
2013 Quarters					
Operating revenue	$1,370.3	$1,299.1	$1,380.9	$1,543.3	$5,593.6
Operating expense	$1,339.2	$1,262.9	$1,393.8	$1,532.6	$5,528.5
Operating income	$ 31.1	$ 36.2	$ (12.9)	$ 10.7	$ 65.1
Net income (loss)	$ 30.7	$ 28.5	$ (13.5)	$ 8.2	$ 53.9
Net income (loss) attributable to noncontrolling interest[(1)]	$ 18.7	$ 17.4	$ (8.3)	$ 5.9	$ 33.7
Net income (loss) attributable to limited partner ownership interests[(1)]	$ 11.8	$ 10.8	$ (5.1)	$ 2.2	$ 19.7
Net income (loss) per limited partner unit[(1)]	$ 0.44	$ 0.41	$ (0.19)	$ 0.06	$ 0.68
2012 Quarters					
Operating revenue	$1,495.9	$1,200.7	$1,220.9	$1,440.4	$5,357.9
Operating expense	$1,458.0	$1,124.2	$1,190.9	$1,413.4	$5,186.5
Operating income	$ 37.9	$ 76.5	$ 30.0	$ 27.0	$ 171.4
Net income	$ 37.2	$ 76.3	$ 28.7	$ 25.3	$ 167.5
Net income attributable to noncontrolling interest[(1)]	$ 22.7	$ 46.6	$ 17.5	$ 15.4	$ 102.2
Net income attributable to limited partner ownership interests[(1)]	$ 14.3	$ 29.0	$ 11.0	$ 9.7	$ 64.0
Net income per limited partner unit[(1)]	$ 0.53	$ 1.09	$ 0.41	$ 0.36	$ 2.40

(1) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% retained by EEP.

20. SUBSEQUENT EVENTS

Distribution to Partners

On January 29, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable of $0.16644 per unit for the quarter ended December 31, 2013. The distribution was paid on February 14, 2014 to unitholders of record on February 7, 2014. This amount represents the prorated target minimum quarterly distribution of $0.31250 per unit, or $1.25 on an annualized basis, for the period from the completion of the Offering through December 31, 2013. We paid $3.5 million to our public Class A common unitholders, while $4.2 million in the aggregate was paid to EEP with respect to its Class A common units, subordinated units and general partner interest.

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

None.

Item 9A. Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Exchange Act within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2013. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Annual Report on Internal Control Over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f).

The Partnership's internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers, and effected by the board of directors of our General Partner, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership's financial statements for external purposes in accordance with generally accepted accounting principles.

The SEC, as required by Section 404 of the Sarbanes-Oxley Act, adopted rules that generally require every registrant that files reports with the SEC to include a management report on such registrant's internal control over financial reporting in its annual report. In addition, our independent registered public accounting firm must attest to our internal control over financial reporting. This first Annual Report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm under a transition period established by SEC rules applicable to new public registrants. Management will be required to provide an assessment of effectiveness of our internal control over financial reporting as of December 31, 2014.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended December 31, 2013.

Item 9B. Other Information

On February 10, 2014, John A. Crum, James G. Ivey, and Edmund P. Segner III were appointed to the board of directors of Midcoast Holdings, L.L.C., the general partner of Midcoast Energy Partners, L.P. Messrs. Crum and Ivey were each appointed to the Audit, Finance and Risk Committee as of the date they were appointed to the board of directors. They are eligible for director compensation as described in Item 11. *Executive Compensation — Director Compensation*. These appointments increase the number of members of the board of directors of Midcoast Holdings, L.L.C. to eight.

On February 11, 2014, C. Gregory Harper entered into an employment agreement with Enbridge Energy Services, Inc. ("EES"), an affiliate of EEP's General Partner. The agreement terminates upon retirement, death, disability or other termination of employment. The agreement provides that EES will pay severance benefits to Mr. Harper if his employment is terminated involuntarily without cause or because of the disability of Mr. Harper, or if his employment is terminated voluntarily for good reason. The benefits include (i) a retiring allowance of two times the sum of his annual salary and the average of the last two annual incentive bonuses paid to Mr. Harper; (ii) an annual incentive bonus for the calendar year in which termination occurs; accrued and unpaid vacation payout; payout under any incentive plans on a pro-rata basis, as provided by such plan; an amount equivalent to EES's portion of 401(k) plan contributions (as provided by such plan) for two years; reimbursement of certain amounts of career counseling within one year following termination and the cash value of two times the last annual flexible perquisite allowance immediately preceding the termination date (less any amounts prepaid, but unearned as of the termination date); (iii) to the extent he has a vested benefit in any defined benefit plan or supplemental benefit pension plan, he will receive a related payout amount as provided in the agreement; (iv) the ability to exercise any vested and exercisable stock options he holds under EES's or affiliate's stock option plans in accordance with the terms of such plans and any related agreements; (v) with respect to unvested options, the cash value of the excess of the fair market value of the shares (or other applicable securities) on the termination date divided by the exercise price for such options. Mr. Harper will be required to sign a release agreement in exchange for such benefits.

The agreement also provides that Mr. Harper will maintain the confidential information of EES and its affiliates and will not solicit business for one year following termination in competition with EES and its affiliates from EES's or its affiliates' partners, customers or prospective partners or customers (as of the termination date) or any person with whom they have a business relationship within one year preceding the termination date. The agreement also provides for a post-termination two year restriction on recruitment of EES and affiliate employees.

The foregoing summary of the agreement is qualified in its entirety by the full terms and conditions of the agreement, a copy of which is filed as Exhibit 10.10 hereto and is incorporated herein by reference.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

We are a limited partnership and have no officers or directors of our own. Set forth below is certain information concerning the directors and executive officers of Midcoast Holdings, L.L.C., our General Partner. Directors are elected by the sole member of our General Partner and hold office until their successors have been elected or qualified or until their earlier death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors. The following table shows information for the directors and executive officers of Midcoast Holdings.

Name	Age	Position
Dan A. Westbrook	61	Director and Chairman of the Board
John A. Crum	61	Director
J. Herbert England	67	Director
James G. Ivey	62	Director
Edmund P. Segner III	60	Director
C. Gregory Harper	49	Director
Mark A. Maki	49	Principal Executive Officer and Director
Terrance L. McGill	59	President and Director
John A. Loiacono	51	Vice President—Commercial Activities
Stephen J. Neyland	46	Vice President—Finance
Kerry C. Puckett	52	Vice President—Engineering and Operations, Gathering & Processing
Janet L. Coy	56	Vice President—Natural Gas Marketing
Noor S. Kaissi	41	Controller
E. Chris Kaitson	57	Vice President—Law and Assistant Secretary
Byron C. Neiles	48	Vice President—Major Projects
Allan M. Schneider	55	Vice President—Regulated Engineering and Operations
Darren Yaworsky	43	Treasurer

DIRECTORS AND NAMED EXECUTIVE OFFICERS

Dan A. Westbrook

Dan A. Westbrook was appointed Chairman of the Board and elected as a director of our General Partner in October 2013 and also serves on the Audit, Finance and Risk Committee. Mr. Westbrook has also served as a director of EEP's general partner and Enbridge Management since October 2007, and serves on the Audit, Finance & Risk Committee of both companies, as well as serving on Special Committees of Enbridge Management. Since 2008, he has also served on the board of the Carrie Tingley Hospital Foundation in Albuquerque, New Mexico. During 2013, Mr. Westbrook was named a director of SandRidge Energy, Inc. From 2001 to 2005, Mr. Westbrook served as president of BP China Gas, Power & Upstream and as vice-chairman of the board of directors of Dapeng LNG, a Sino joint venture between BP subsidiary CNOOC Gas & Power Ltd. and other Chinese companies. He held executive positions with BP in Argentina, Houston, Russia, Chicago and the Netherlands before retiring from the company in January 2006. From August 2002 to June 2004, Mr. Westbrook served as director and chairman of the finance committee of the International School of Beijing. He is a former director of Ivanhoe Mines, now known as Turquoise Hill Resources Ltd., an international mining company, Synenco Energy Inc., a Calgary-based oil sands company, and Knowledge Systems Inc., a privately-held U.S. company that provides software and consultant services to the oil and gas industry.

Through his long career in the petroleum exploration and production industry, including his other public company directorships and previous service as President of BP China, Mr. Westbrook provides the board of directors with extensive industry experience, leadership skills, international and petroleum development experience, as well as knowledge of our business environment.

John A. Crum

John A. Crum was appointed a director of our General Partner on February 10, 2014 and also was appointed to serve on the Audit, Finance and Risk Committee. Mr. Crum is currently serving as Midstates Petroleum Company, Inc.'s Chairman, President and Chief Executive Officer, positions he has held since 2011. He also serves on the board of directors of Coskata, Inc. a private biofuel technology company, since August 2012. From 1995 to 2011, Mr. Crum served in several roles for various Apache Corporation divisions, including Co-Chief Operating Officer and President, North America from 2009 to 2011. Some previous positions held by Mr. Crum include Vice President of Engineering and Operations of Aquila Energy Corporation from 1993 to 1995 and District Manager and Regional Manager for Pacific Enterprises Oil Company from 1986 to 1993.

Mr. Crum brings to the board almost forty years of experience in the energy industry in a variety of engineering and management roles, including leadership through an initial public offering.

J. Herbert England

J. Herbert England was elected a director of our General Partner in October 2013 and serves as the Chairman of the Audit Finance & Risk Committee of our General Partner. Mr. England has also served as a director of each of EEP's general partner and Enbridge Management since July 2012 and serves as the Chairman of the Audit, Finance & Risk Committee of both companies. In addition, Mr. England serves on the Enbridge board of directors and the board of directors of FuelCell Energy, Inc. He has been Chair & Chief Executive Officer of Stahlman-England Irrigation Inc., a contracting company in southwest Florida, since 2000. From 1993 to 1997, Mr. England was the Chair, President & Chief Executive Officer of Sweet Ripe Drinks Ltd., a fruit beverage manufacturing company. Prior to 1993, Mr. England held various executive positions with John Labatt Limited, a brewing company, and its operating companies, Catelli Inc., a food manufacturing company, and Johanna Dairies Inc., a dairy company.

Mr. England brings to the board of directors a wide range of financial executive experience because of his previous positions, as well as his service with other public company audit committees.

James G. Ivey

James G. Ivey was appointed a director of our General Partner on February 10, 2014 and also was appointed to serve on the Audit, Finance and Risk Committee. Mr. Ivey currently co-heads Pintail Energy, an exploration and production company he co-founded in 2014. Mr. Ivey currently serves on the boards of directors of two privately held independent power producing companies, National Energy & Gas Transmission, Inc. since 2004 and Mach Gen LLC since 2004. His prior experience includes serving Milagro Exploration from 2009 to 2012 in the role of Executive Vice President and Chief Financial Officer (2009-2010) and then President and Chief Executive Officer (2010-2012). From 2006 to 2008, Mr. Ivey was Executive Vice President and Chief Financial Officer of Cobalt International Energy. From 2004 to 2006, Mr. Ivey served Markwest Hydrocarbon as Senior Vice President and Chief Financial Officer. His previous background includes serving as the Corporate Treasurer for each of Williams Companies (1995-2004) and Arkla Gas (1982-1995) as well as other financial and engineering positions with Conoco and Fluor from 1973 to 1981.

Mr. Ivey brings to the board of directors over forty years of experience in the oil and gas industry in the exploration and production areas, as well as MLP midstream experience in engineering, finance and corporate governance.

Edmund P. Segner III

Edmund P. Segner III was appointed a director of our General Partner on February 10, 2014. Mr. Segner is currently a professor in the practice in the Department of Civil and Environmental Engineering at Rice University and serves on the boards of directors of three other companies and audit committees, as follows: Bill Barrett Corp., an oil and gas exploration and production company, since August 2009, Exterran GP LLC, the general partner of Exterran Partners, L.P., a master limited partnership which provides contract operations since

May 2009, and Laredo Petroleum Holdings, Inc., a Permian oil and gas exploration and development company since August 2011. Mr. Segner retired from EOG Resources, Inc. in 2008. He had held several offices at EOG during his tenure from 1997 to 2008 including President, Chief of Staff and Director and principal financial officer. Formerly, from 1988 to early 1998, Mr. Segner held several positions with Enron Corporation, including Vice President, Senior Vice President and Executive Vice President. Previously, Mr. Segner also served on the boards of Seahawk Drilling from 2009 to 2011 and of Universal Compression Holdings from 2000-2002. He has also served as a member of the board or as a trustee for several nonprofit organizations.

Mr. Segner brings to the board his broad experience in management, his experience with master limited partnerships and his financial expertise as well as his audit committee experience.

C. Gregory Harper

C. Gregory Harper was appointed to the board of directors of the General Partner on January 30, 2014. Mr. Harper has also served as a director of each of EEP's general partner and Enbridge Management since January 30, 2014. Mr. Harper also was appointed as President, Gas Pipelines and Processing for Enbridge effective January 30, 2014. He is also on the board of directors of Sprague Operating Resources LLC since October 2013. Mr. Harper joins Midcoast Holdings and its affiliates from Southwestern Energy Company, where he held the position of Senior Vice President, Midstream since 2013. Prior to joining Southwestern Energy Company, Mr. Harper served CenterPoint Energy, Inc. as Senior Vice President and Group President, Pipelines and Field Services since December 2008. Before joining CenterPoint Energy in 2008, Mr. Harper served as President, Chief Executive Officer and as a Director of Spectra Energy Partners, LP from March 2007 to December 2008. From January 2007 to March 2007, Mr. Harper served as Group Vice President of Spectra Energy Corp., and he was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper was Senior Vice President of Energy Marketing and Management for Duke Energy North America from January 2003 until January 2004 and Vice President of Business Development for Duke Energy Gas Transmission and Vice President of East Tennessee Natural Gas, LLC from March 2002 until January 2003. He served on the Board of Directors and as Chairman of the Interstate Natural Gas Association of America from 2013.

Mr. Harper brings to the board insight and in-depth knowledge of our industry. He also provides leadership skills, pipeline operations and management expertise and knowledge of our local community and business environment, which he has gained through his long career in the oil and gas industry.

Mark A. Maki

Mark A. Maki was appointed Principal Executive Officer of our General Partner in October 2013 and he has served as a director of our General Partner since May 2013. Mr. Maki previously served as President of our General Partner from May 2013 to October 2013. He was appointed President and Principal Executive Officer of EEP's general partner and Enbridge Management on January 30, 2014 and has served both companies as a director since October 2010. Mr. Maki previously served as President of Enbridge Management and Senior Vice President of EEP's general partner from October 2010. He also served Enbridge in the functional title of Acting President, Gas Pipelines during 2013. Mr. Maki previously served as Vice President—Finance of EEP's general partner and Enbridge Management from July 2002 to October 2010. Prior to that time, Mr. Maki served as Controller of EEP's general partner and Enbridge Management from June 2001, and prior to that, as Controller of Enbridge Pipelines from September 1999.

Mr. Maki progressed through a series of accounting and financial roles of increasing responsibility during his 27 years with Enbridge in the United States and Canada. Through his broad range of domestic and Canadian experience in the pipeline industry, Mr. Maki provides the board of directors with financial expertise, leadership skills in our industry and knowledge of our local community and business environment.

Terrance L. McGill

Terrance L. McGill was appointed President of our General Partner in October 2013 and has served as a director of our General Partner since May 2013. From May 2013 to October 2013, Mr. McGill served as Chief Operating Officer of our General Partner. Mr. McGill has served as Senior Vice President of EEP's general partner and of Enbridge Management since January 2014 and October 2010, respectively and has served as a director of both companies since May 2006. Previously, Mr. McGill served as President of EEP's general partner and Enbridge Management from May 2006. Prior to May 2006, Mr. McGill served as Vice President—Commercial Activity and Business Development of the General Partner and Enbridge Management from April 2002 and Chief Operating Officer from July 2004. Prior to that time, Mr. McGill was President of Columbia Gulf Transmission Company from January 1996 to March 2002.

Mr. McGill gives its board of directors insight and in-depth knowledge of our industry and our specific operations and strategies. He also provides leadership skills, pipeline operations and management expertise and knowledge of our local community and business environment, which he has gained through his long career in the oil and gas industry.

John A. Loiacono

John A. Loiacono was appointed Vice President—Commercial Activities of our General Partner in May 2013. Mr. Loiacono has served as Vice President—Commercial Activities of EEP's general partner and Enbridge Management since July 2006. Prior to that, he was Director of Commercial Activities for our General Partner and Enbridge Management from April 2003 and commenced employment with Midcoast Energy Resources, Inc. in February 2000 as an Asset Optimizer until it was acquired by Enbridge in May 2001.

Stephen J. Neyland

Stephen J. Neyland was appointed Vice President—Finance of our General Partner in May 2013. Mr. Neyland has served as Vice President—Finance of EEP's general partner and Enbridge Management since October 2010. Mr. Neyland was previously Controller of EEP's general partner and Enbridge Management effective September 2006. Prior to his appointment, he served as Controller—Natural Gas from January 2005, Assistant Controller from May 2004 to January 2005 and in other managerial roles in finance and accounting from December 2001 to May 2004. Prior to that time, Mr. Neyland was Controller of Koch Midstream Services from 1999 to 2001.

Kerry C. Puckett

Kerry C. Puckett was appointed Vice President—Engineering and Operations, Gathering & Processing of our General Partner in May 2013. Mr. Puckett has served as Vice President—Engineering and Operations, Gathering & Processing of EEP's general partner and Enbridge Management since October 2007. Prior to his appointment, he served as General Manager of Engineering and Operations from 2004 and Manager of Operations from 2002 to 2004. Prior to that time, he served as Manager of Business Development for Sid Richardson Energy Services Company.

OTHER EXECUTIVE OFFICERS

Janet L. Coy was appointed Vice President—Natural Gas Marketing of our General Partner in May 2013. Ms. Coy has served as Vice President—Natural Gas Marketing of EEP's general partner and Enbridge Management since October 2010. Ms. Coy previously served as President of the Natural Gas Marketing subsidiaries of Enbridge Management and EEP's general partner since the acquisition of Midcoast Energy Resources, Inc. in May 2001 and continues to serve in that capacity.

Noor S. Kaissi was appointed Controller of our General Partner in July 2013. Ms. Kaissi has also served EEP's general partner and Enbridge Management as Controller since July 2013. Prior to her appointment as Controller for these companies, Ms. Kaissi served as Chief Auditor and in other managerial roles of EEP's general partner and Enbridge Management and more recently with our General Partner with responsibility for financial accounting, internal audit and controls from June 2005.

E. Chris Kaitson was appointed Vice President—Law and Assistant Secretary of our General Partner in May 2013. Mr. Kaitson has served as Vice President—Law and Assistant Secretary of EEP's general partner and Enbridge Management since May 2007. He also currently serves as Deputy General Counsel of Enbridge. Prior to that, he was Assistant General Counsel and Assistant Secretary of EEP's general partner and Enbridge Management from July 2004. He served as Corporate Secretary of EEP's general partner and Enbridge Management from October 2001 to July 2004. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until it was acquired by Enbridge in May 2001.

Byron C. Neiles was appointed Vice President—Major Projects of our General Partner in May 2013. He was elected Senior Vice President—Major Projects of EEP's general partner and Enbridge Management in April 2013. Previously, Mr. Neiles served EEP's general partner and Enbridge Management as Vice President- Major Projects from October 2010. Additionally, Mr. Neiles has served Enbridge as Senior Vice President—Major Projects since November 2011 and previously served Enbridge as Vice President in the Major Projects division since April 2008, prior to which he was Vice President of Enbridge Gas Distribution from 2003 to 2008. Mr. Neiles joined Enbridge in 1994.

Allan M. Schneider was appointed Vice President—Regulated Engineering and Operations of our General Partner in May 2013. Mr. Schneider has served as Vice President—Regulated Engineering and Operations of EEP's general partner and Enbridge Management since October 2007. Prior to his appointment, he served as Director of Engineering and Operations for Regulated & Offshore and Director of Engineering Services from January 2005. Prior to that, Mr. Schneider was Vice President of Engineering and Operations for Shell Gas Transmission, L.L.C. from December 2000.

Darren J. Yaworsky was appointed Treasurer of our General Partner in May 2013. Mr. Yaworsky has served as Treasurer of EEP's general partner and Enbridge Management since October 2012. He is also Director—Treasury, for Enbridge, a position he has held since 2011. Mr. Yaworsky has held the following positions since joining Enbridge in 2008: From 2010 to 2011, he served as Senior Manager—Treasury and from 2008 to 2010 he was Manager—Treasury. Prior to joining Enbridge, Mr. Yaworsky was Managing Director with Bank of Montreal from 2005 to 2008 and has worked in the banking industry since 1998.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our directors, executive officers and 10% beneficial owners to file with the SEC reports of ownership and changes in ownership of our equity securities and to furnish us with copies of all reports filed. Based on our review of the Section 16(a) filings that have been received by us and the written representations made by our directors and executive officers, we believe that all filings required to be made under Section 16(a) during 2013 were timely made except for one late Form 4 filed by Enbridge Energy Partners, L.P. related to the repurchase by us of 2,775,000 Class A common units in December 2013.

GOVERNANCE MATTERS

We are a "controlled company," as that term is used in NYSE Rule 303A, because all of our voting units are owned by our General Partner. Because we are a controlled company, the NYSE listing standards do not require that we or our General Partner have a majority of independent directors or a nominating or compensation committee of our General Partner's board of directors.

The NYSE listing standards require our principal executive officer to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. Accordingly, this certification will be provided as required to the NYSE.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

We have adopted a Code of Ethics applicable to our General Partner's senior officers, including the principal executive officer, principal financial officer and principal accounting officer of Midcoast Holdings. A copy of the Code of Ethics for Senior Financial Officers is available on our website at *www.midcoastpartners.com*. We post on our website any amendments to or waivers of our Code of Ethics for Senior Officers and we intend to satisfy any disclosure requirements that may arise under Form 8-K relating to this information through such postings. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how our board of directors should function and its position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at *www.midcoastpartners.com*. We post on our website any amendments to our Corporate Governance Guidelines, and we intend to satisfy any disclosure requirements that may arise under Form 8-K relating to these amendments through such postings. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

AUDIT, FINANCE & RISK COMMITTEE

MEP's General Partner has an Audit, Finance & Risk Committee, referred to as the "Audit Committee," comprised of four board members who are independent as the term is used in Section 10A of the Exchange Act. None of these members are relying upon any exemptions from the foregoing independence requirements. The members of the Audit Committee are John A. Crum, J. Herbert England, James G. Ivey and Dan A. Westbrook. J. Herbert England is chairman of the Audit Committee. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the report of the independent registered public accounting firm. The Audit Committee also reviews the scope and quality, including the independence and objectivity, of the independent and internal auditors and the fees paid for both audit and non-audit work and makes recommendations concerning audit matters, including the engagement of the independent auditors, to the Board of Directors.

The charter of the Audit Committee is available on our website at *www.midcoastpartners.com*. The charter of the Audit Committee complies with the listing standards of the NYSE currently applicable to us. This material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

The General Partner's Board of Directors has determined that J. Herbert England and James G. Ivey each qualify as "audit committee financial experts" as defined in Item 407(d)(5)(ii) of Regulation S-K. Each of the members of the Audit Committee is independent as defined by Section 303A of the listing standards of the NYSE.

Mr. England serves on the audit committees of the General Partner and the general partner of Enbridge Energy Partners, L.P., Enbridge Management, FuelCell Energy, Inc., and Enbridge Inc. In compliance with the provisions of the Audit Committee Charter, the boards of directors of the General Partner and of Enbridge Management and the general partner of Enbridge Energy Partners, L.P. have determined that Mr. England's simultaneous service on such audit committees does not impair his ability to effectively serve on the Audit Committee.

The General Partner's Audit Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our Audit Committee may do so by writing to the Chairman, Audit Committee, c/o Midcoast Holdings, L.L.C., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of the General Partner meet at regularly scheduled executive sessions without management. Dan A. Westbrook serves as the presiding director at those executive sessions. Persons wishing to communicate with the Company's independent directors may do so by writing to the Chairman, Board of Directors, Midcoast Holdings, L.L.C., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

General

We are a master limited partnership and do not directly employ any employees, nor do we have executive officers or directors. We are managed by our General Partner and the Named Executive Officers, or NEOs, who are executive officers of our General Partner. Our General Partner is wholly owned and controlled by EEP, which is also a master limited partnership and does not directly employ any employees. We entered into an intercorporate services agreement with EEP, which is managed and controlled by Enbridge Management, to provide us with managerial, administrative and operational services. EEP's General Partner, Enbridge Management and Enbridge, through its affiliates, provide managerial, administrative, operational and director services to EEP pursuant to service agreements among them and EEP. Pursuant to our intercorporate services agreement, we will reimburse EEP for an allocated portion of the costs of these services, which costs include a portion of the compensation of the NEOs.

The boards of directors of Enbridge Management, Enbridge and our General Partner do not have compensation committees, nor do they have responsibility for approving the elements of compensation for the NEOs presented in the tables following this discussion. The boards of directors of Enbridge Management, Enbridge and our General Partner, as part of our annual budgeting process, however, do have responsibility for evaluating and determining the reasonableness of our overall budget. The budget includes compensation amounts to be allocated to us for managerial, administrative, operational and director support to be provided by our General Partner, Enbridge Management and Enbridge and its affiliates pursuant to the intercorporate service agreement mentioned above. The budgeted amount of total compensation includes the portion of the compensation of the NEOs that will be allocated to us and is discussed in more detail below.

Since we do not have direct employees or directors, and our General Partner and Enbridge Management do not have responsibility for approving the elements of compensation for the NEOs, we, our General Partner and Enbridge Management do not have compensation policies. The compensation policies and philosophy of Enbridge govern the types and amounts of compensation of each of the NEOs. The NEOs at December 31, 2013 were:

- Mark A. Maki, Principal Executive Officer and Director
- Terrance L. McGill, President and Director
- Stephen J. Neyland, Vice President—Finance
- John A. Loiacono, Vice President—Commercial Activities; and
- Kerry C. Puckett, Vice President—Engineering and Operations, Gathering and Processing.

Messrs. Maki, McGill, Neyland, Loiacono and Puckett are also officers of EEP's general partner and Enbridge Management. Compensation of our NEOs is determined as part of an Enbridge enterprise-wide review process. Each business unit develops a salary increase budget recommendation, in consultation with the Enbridge corporate compensation department, based on a competitive analysis of the labor market for that business unit. These recommendations are presented, in summary and on a business unit basis, to the Human Resources and Compensation Committee of the board of directors of Enbridge, or the HRC Committee, for approval. Individual salary increases are implemented after the HRC Committee approves the overall budget. Compensation adjustments for senior leadership of the various business units are recommended by their supervisors and reviewed by the executive leadership team of Enbridge. The Enbridge executive leadership team and the President & Chief Executive Officer of Enbridge review the elements of compensation for all our NEOs. Enbridge's President & Chief Executive Officer approves the individual salary increase recommendations, on an enterprise-wide basis, to ensure that compensation expense is within the budget approved by the HRC Committee. Each of the NEOs provides services to other affiliates of Enbridge and, therefore, his compensation is determined on the basis of his overall performance with respect to Enbridge and all of its affiliates and not solely based on his performance with respect to us or EEP.

We are a partnership and not a corporation for United States federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Internal Revenue Code §162(m). In addition, we are not the employer for any of the NEOs.

In 2013, the board of directors of Enbridge implemented an Incentive Compensation Clawback Policy that will enable it to recover, from current and former executives, certain incentive compensation amounts that were awarded or paid to such individuals based upon the achievement of financial results that are subsequently materially restated or corrected, in whole or in part, if such individuals engaged in fraud or willful misconduct that resulted in the need for such restatement or correction and it is determined that the incentive compensation paid to the individuals would have been lower based on the restated or corrected results.

For a more detailed discussion of the compensation policies and philosophy of Enbridge, we refer you to a discussion of those items as set forth in the Executive Compensation section of the Enbridge Management Information Circular, or MIC, on the Enbridge website at www.enbridge.com. The Enbridge MIC is produced by Enbridge pursuant to Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Exchange Act. We refer to the MIC to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our General Partner.

Elements of Compensation

The HRC Committee sets the compensation philosophy of Enbridge, which is approved by the Enbridge board of directors. Enbridge has a pay-for-performance philosophy and programs that are designed to be aligned with its interests, on an enterprise-wide basis, as well as the interests of its shareholders. A significant portion of total direct compensation of Enbridge's senior management is dependent on actual performance measured against short, medium and long-term performance goals of Enbridge, on an enterprise-wide basis, which are approved by the Enbridge board of directors. As a business unit of Enbridge, we and EEP contribute to its overall growth, earnings and attainment of performance goals.

The elements of total compensation in 2013 for Messrs. Maki, McGill, Neyland, Loiacono and Puckett, are:

- Base Salary—to provide a fixed level of compensation for performing day-to-day responsibilities, while balancing the individual's role and competency, market conditions and issues of attraction and retention.
- Short-term incentive—to provide a competitive, performance-based cash award based on pre-determined corporate, business unit and individual goals that measure the execution of the business strategy over a one-year period.

- Medium-term and long-term incentives—to recognize contributions and provide competitive, performance-based compensation comprised of performance stock units and incentive stock options that are tied to the share price of Enbridge common shares, and are mostly at-risk to motivate performance over the medium and long term.
- Pension plan—to provide a competitive retirement benefit.
- Savings plan—to promote ownership of Enbridge common shares and to provide the opportunity to save additional funds for retirement or other financial goals.
- Perquisites—to provide a competitive allowance to offset expenses largely related to the executive's role.
- Benefits—to provide security pertaining to health and welfare risks in a flexible manner to meet individual needs.

The HRC Committee makes determinations as to whether the enterprise-wide performance goals have been achieved, approves business unit results and makes adjustments as necessary to more accurately reflect whether those goals have been met or exceeded. For example, the HRC Committee may determine to disregard a non-cash gain or loss reflected in our results of operations that resulted from mark-to-market accounting for our derivative activities in determining whether certain goals have been met.

Base Salary

Base salary for the NEOs reflects a balance of market conditions, role, individual competency and attraction and retention considerations and takes into account compensation practices at peer companies of Enbridge. Increases in base pay for all NEOs are based primarily on competitive considerations.

Short-Term Incentive Plan

The Enbridge short-term incentive plan, or STIP, is designed to provide incentive for, and to reward, the achievement of goals that are aligned with the Enbridge annual business plan. The target short-term incentive reflects the level of responsibility associated with the NEO's role and competitive practice and is expressed as a percentage of base salary. Actual incentive awards can range from zero to two times the target. Awards under the plan are based on performance relative to goals achieved at the Enbridge corporate level, business unit level and individual level. Performance relative to goals in each of these areas is reflected on a scale of zero to two; zero indicates performance was below threshold levels, one indicates that goals were achieved and two indicates that performance was exceptional. Enbridge corporate performance is a factor in determining incentive awards.

The following is a summary for 2013 of the incentive targets, payout range, and relative weightings between the Enbridge corporate, business unit and individual performance:

			Relative Weighting		
	Target STIP%[1]	Pay Out Range	Corporate	Business Unit	Individual
Mark A. Maki *Principal Executive Officer and Director*	40%	0-80%	25%	50%	25%
Terrance L. McGill *President and Director*	40%	0-80%	25%	50%	25%
Stephen J. Neyland *Vice President—Finance*	35%	0-70%	25%	50%	25%
John A. Loiacono *Vice President—Commercial Activities*	35%	0-70%	25%	50%	25%
Kerry C. Puckett *Vice President—Engineering and Operations, Gathering and Processing*	35%	0-70%	25%	50%	25%

(1) All values are expressed as percentages of base salary.

The overall performance multiplier and STIP are calculated as follows:

Performance multiplier		STIP	
	Corporate target incentive opportunity x (0-2)		Base Salary $
+	Business unit target incentive opportunity x (0-2)	x	Target STIP %
+	Individual target incentive opportunity x (0-2)	x	Overall performance multiplier (0-2)
=	Overall performance multiplier (0-2)	=	$ Short term incentive award

Enbridge Corporate Performance

Corporate performance is measured by adjusted earnings per share, or EPS. This is a metric that focuses on return to shareholders and is aligned with how investors and security analysts assess Enbridge's performance on an annual basis.

The adjusted EPS metric represents a significant component of the named executives' short-term incentive award at 25%. Enbridge's 2013 EPS guidance range was $1.74 Canadian Dollars, or CAD, to $1.90 CAD, as approved by the Enbridge Board prior to the start of 2013. Actual performance was $1.78 CAD. Adjustments are made to ensure the result is a fair reflection of performance. Approximately $988 million CAD was adjusted out of the calculation, including mark-to-market gains/losses and tax on intercompany gains and sales. The corporate multiplier ranges from 0 to 2.0, with 1.0 meaning that the performance measure was met.

During 2013, Enbridge management undertook, with Enbridge board approval, a supplementary financing plan that included common equity and preferred equity pre-funding actions that were not provided for in the original budget, prompted by significant expansions to the company's five-year growth capital plan, which emerged over the course of the year. Although these actions had an adverse impact on Enbridge's 2013 EPS, they were necessary and prudent steps to support the medium and long-term objectives of Enbridge. At the same time, an unanticipated change in the account methodology applicable to three of Enbridge's contract pipelines resulted in a small, but positive variance to 2013 budgeted EPS generated by these assets. The HRC Committee approved an adjustment to the calculated EPS result utilized for the corporate performance multiplier for short-term incentive purposes only, to better align the short-incentive awards for employees with the positive near-term and long-term outcomes for shareholders and Enbridge. Adjusting out the negative impact of the specific pre-funding actions and the positive impact of the change in accounting methodology noted above, resulted in an adjusted EPS of $1.815 CAD (versus $1.78 CAD per share) and a short-term corporate multiplier of 0.94 out of 2.0.

Enbridge Business Unit Performance

Business unit performance measures vary among the NEOs to reflect the annual business plans and operations for which each NEO is accountable. Performance is measured against targets that are established at the beginning of the year. The detailed business unit performance measures for each of the NEOs are set forth in the tables which follow.

The business performance measure for each NEO is designed to reflect their multiple responsibilities at Enbridge. For 2013, Mr. Maki's performance measure is calculated at 56% for the Gas Transportation business unit, 27% for the Gas Development business unit and 17% for the Shared Services business unit, resulting in a business unit multiplier of 1.17 out of 2.0. For 2013, Mr. McGill's performance measure is calculated at 75% for the Gas Transportation business unit and 25% for the Gas Development business unit, resulting in a business unit multiplier of 1.18 out of 2.0. For 2013, Mr. Neyland's performance measure is calculated at 100% for the Shared Services business unit, resulting in a business unit multiplier of 1.05 out of 2.0. For 2013, Messers. Loiacono's and Puckett's performance measure is calculated at 100% for the gas transportation business unit, resulting in a business unit multiplier of 1.13 out of 2.0.

The business unit multipliers upon which the NEO's STIP is calculated are included in the following tables. They reflect rounding and range from 0 to 2.0, with 1.0 meaning that the performance measure was met. The business units include the Partnership, but also include portions of other Enbridge businesses.

Gas Transportation					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Rating**	**Performance Multiplier**
Safety	20%	Health & Safety Training Safety Observations Total Recordable Injury Frequency Contributory Motor Vehicle Accidents	6% 6% 4% 4%	1.08	0.21
Operations & Integrity	25%	Integrity Management & Process Safety	25%	1.56	0.39
Financial	40%	Budgeted Earnings	40%	0.60	0.24
Employee Engagement & Compliance	15%	Healthy Workforce Initiative Employee Development SOX Compliance	5% 5% 5%	1.91	0.29
		Business Unit Performance Multiplier			**1.13**

Gas Development					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Rating**	**Performance Multiplier**
Operations, Safety & Integrity	25%	Asset Transition and Risk Reduction Management Plan Safety Observations Total Recordable Injury Frequency Contributory Motor Vehicle Incidents	11% 6% 4% 4%	1.25	0.31
Financial	40%	Budget Earnings	40%	1.11	0.44
Business Development	35%	Contracting Strategies & New Investments	35%	1.64	0.58
		Business Unit Performance Multiplier			**1.33**

Shared Services					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Rating**	**Performance Multiplier**
Safety	20%	Health & Safety Training Safety Observations Total Recordable Injury Frequency Contributory Motor Vehicle Incidents	6% 6% 4% 4%	1.08	0.21
Operations & Integrity	25%	Integrity Management & Process Safety	25%	1.56	0.39
Financial	40%	Budgeted Earnings	40%	0.40	0.16
Employee Engagement & Compliance	15%	Healthy Workforce Initiative Employee Development Sox Compliance	5% 5% 5%	1.91	0.29
		Business Unit Performance multiplier			**1.05**

Individual Performance

Each of the NEOs establishes individual goals at the beginning of each year by which individual performance is measured. These goals are based on areas of strategic and operational emphasis related to their respective portfolios, development of succession candidates, employee engagement, community involvement and leadership. The level of attainment of individual performance goals is recommended by their respective leaders to the Enbridge executive leadership team.

Summary of 2013 Performance Multipliers

The following table summarizes the corporate, business unit and individual performance multipliers for each executive, associated weights and overall performance multiplier result:

NEO	Corporate Performance (a) (Weight x Multiplier)	Business Unit Performance (b) (Weight x Multiplier)	Individual Performance (c) (Weight x Multiplier)	Overall Performance Multiplier (a+b+c)
Mark A. Maki	25% x 0.94 = 0.24	50% x 1.17 = 0.58	25% x 1.60 = 0.40	1.22
Terrance L. McGill	25% x 0.94 = 0.24	50% x 1.18 = 0.59	25% x 1.60 = 0.40	1.23
Stephen J. Neyland	25% x 0.94 = 0.24	50% x 1.05 = 0.53	25% x 1.70 = 0.42	1.19
John A. Loiacono	25% x 0.94 = 0.24	50% x 1.13 = 0.56	25% x 1.55 = 0.39	1.19
Kerry C. Puckett	25% x 0.94 = 0.24	50% x 1.13 = 0.56	25% x 1.65 = 0.41	1.21

Based on the overall performance multiplier determined from the above table, short term incentive awards for our executives were calculated as follows:

NEO	Base Salary (a)	Target (b)	Overall Performance Multiplier (c)	Calculated STIP(1) =(a) x (b) x (c)	Actual STIP
Mark A. Maki	$ 348,712	40%	1.22	$ 170,171	$ 220,170
Terrance L. McGill	383,904	40%	1.23	188,113	188,120
Stephen J. Neyland	252,206	35%	1.19	104,602	134,610
John A. Loiacono	253,656	35%	1.19	105,426	115,430
Kerry C. Puckett	248,268	35%	1.21	105,359	115,370

(1) The calculated STIP may differ from the amounts presented due to rounding.

The calculated STIP may be adjusted for our NEOs, except Mr. Maki, by Enbridge's executive leadership team for fairness and consistency with enterprise-wide compensation, while any adjustment for Mr. Maki would be recommended and approved by the President & Chief Executive Officer of Enbridge. Messrs. Maki, Neyland, Puckett and Loiacono received additional STIP awards above the computed amounts as a result of exceptional performance and contribution to Enbridge and the Partnership.

Medium and Long-Term Incentives

Enbridge has three plans that make up its medium and long-term incentive program for senior management:

- A performance stock unit plan, or PSUP, which includes three-year phantom shares with performance conditions that impact payout;
- An incentive stock option plan, or ISOP, which includes 10-year stock options to acquire Enbridge common shares with time vesting conditions; and
- A long-term incentive plan, or LTIP, which includes restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights with performance conditions that impact payout.

Enbridge believes that the combination of these medium and long-term incentive plans aligns a component of executive compensation with the interests of Enbridge shareholders beyond the current year. A significant percentage of the value of the annual long-term incentive awards to the NEOs is contingent on meeting performance criteria, such as share price hurdles or other performance measures under the LTIP and PSUP. Specifically, when earnings targets are achieved, the share price increases over the long term and when Enbridge common shares perform well relative to its peer organizations, the value of the medium and long-term incentive is maximized for the executives while also benefitting shareholders. For a more detailed discussion on the LTIP, we refer you to a discussion of this item as set forth in the *Compensation of Our Officers and Directors* section of our Prospectus (Form 424B4) filed November 8, 2013 on the www.sec.gov website. The mix of medium and long-term incentive programs and total target medium and long-term incentive opportunity, expressed as a percentage of base salary, are as follows:

NEO	Target Medium & Long-term Incentive Grant[1]	Amount Each Plan Contributes to Total Target Grant[1]	
		Performance Stock Units	Incentive Stock Options
Mark A. Maki	85.0%	25.5%	59.5%
Terrance L. McGill	85.0%	25.5%	59.5%
Stephen J. Neyland	70.0%	21.0%	49.0%
John A. Loiacono	70.0%	21.0%	49.0%
Kerry C. Puckett	70.0%	21.0%	49.0%

(1) All values are expressed as percentages of base salary.

Actual award values, expressed as a percentage of base salary, range between 0% and 200% of the target medium and long-term incentive opportunity, based on individual performance history, succession potential, retention considerations and market competitiveness.

PSUP

The PSUP is a three-year performance-based unit plan. Performance measures and targets are established at the start of the term to reflect the mid-term objectives of Enbridge in the execution of its strategic plan. Achievement of the performance targets can decrease or increase the final award value in a range of 0% to 200%. PSUs do not involve the issuance of any shares of common stock of Enbridge. Throughout the term, units are added to the grants as if dividends were received and reinvested into additional units based on the actual dividend rate for shares of Enbridge common stock. Awards are granted annually and paid in cash at the end of a three-year term based on two performance criteria that were established for the grant: EPS and relative price to earnings ratio, or P/E Ratio, each of which are weighted at 50%. These metrics remain applicable for the 2013 grant.

The EPS performance reflects Enbridge's commitment to its shareholders to achieve earnings that meet or exceed industry growth rates. Enbridge established the EPS target to reflect performance that would be consistent with the average growth rate forecast of peer companies over a comparable time period. The EPS required to achieve a two multiplier (the maximum) would demonstrate achievement of compound annual growth consistent with exceptional industry growth rate and would represent exceptional performance to the investment community. Performance must at least meet 3% compound annual growth in EPS for a threshold payment, below which the multiplier would be zero.

The second performance criterion is the Enbridge P/E Ratio relative to a selected comparator group of companies. Enbridge's price to earnings performance has historically been very strong, therefore performance below the median of the peer group results in a multiplier of zero, performance between the median and 75th percentile results in a multiplier of one and performance above the 75th percentile results in a multiplier of two. The following table presents the comparator group for the P/E Ratio.

Price/Earnings Ratio—Comparator Group of Companies	
Ameren Corporation	OGE Energy Corp.
Canadian Utilities Limited	ONEOK, Inc.
Centerpoint Energy, Inc.	PG&E Corporation
Emera Incorporated	Sempra Energy
Fortis Inc.	Spectra Energy Corp.
National Fuel Gas Company	TransAlta Corporation
NiSource Inc.	TransCanada Corporation

This peer group of companies was selected because they are all capital market competitors of Enbridge, have a similar risk profile and are in a comparable sector.

ISOP

Regular stock options focus the Enbridge executives on increasing shareholder value over the long-term through common share price appreciation. Stock options are granted annually to Enbridge executives entitling them to acquire Enbridge common shares at a price defined at the time of grant. These options become exercisable over a period of four years at a rate of 25% per year, and the term of each grant of options is ten years.

LTIP

The 2013 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or our LTIP, under which our General Partner may issue long-term equity based awards to directors, officers and employees of our General Partner or its affiliates, or to any consultants, affiliates of our General Partner or other individuals who perform services for us, provided that while we are an affiliate of Enbridge, any directors and consultants who are not also employees of our General Partner or its affiliates will not be eligible to receive awards under the LTIP. The LTIP provides for the grant, from time to time at the discretion of the board of directors of our General Partner or any delegate thereof, subject to applicable law, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and other unit-based awards, provided that while we are an affiliate of Enbridge, awards will only be granted following a recommendation of the board of directors or compensation committee of Enbridge. The purpose of awards under the LTIP is to provide additional incentive compensation to individuals providing services to us, and to align the economic interests of such individuals with the interests of our unitholders. The LTIP limits the number of units that may be delivered pursuant to vested awards to 3,750,000 Class A common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units subject to awards that are cancelled, forfeited, withheld to satisfy exercise prices or tax withholding obligations or otherwise terminated without delivery of the common units will be available for delivery pursuant to other awards. We will be responsible for the cost of awards granted under our LTIP and all determinations with respect to awards to be made under our LTIP will be made by the board of directors of our General Partner or any committee thereof that may be established for such purpose or by any delegate of the board of directors or such committee, subject to applicable law, which we refer to as the plan administrator.

Service Agreements and Allocation of Compensation to the Partnership

EEP provides managerial, administrative, operational and director services to us pursuant to the intercorporate services agreement, which services are ultimately provided through service agreements among EEP, Enbridge Management and Enbridge and its affiliates. Pursuant to the intercorporate services agreement, we reimburse EEP for our allocated portion of the costs of such services. Through a services agreement between our General Partner and EEP, we are charged for the services of executive management resident in the United States, including Messrs. Maki, McGill, Neyland, Loiacono and Puckett.

EEP determines a budgeted allocation rate for our NEOs' compensation in accordance with the terms of the agreements it has entered into with Enbridge Management, Enbridge and its affiliates and provides reimbursement for costs of services based on allocation method provided under those agreements. Since the allocation rate is estimated, the actual time spent by an NEO on behalf of EEP (which includes services to us) may vary from the budgeted allocation rate, and EEP may be allocated more or less of that NEO's compensation than the actual percentage of his time spent on its behalf in a given year. The amount of our NEOs' compensation that is allocated by EEP to us is determined in accordance with the terms of the intercorporate services agreement. For additional information, regarding our intercorporate services agreement, please read Item 13. *Certain Relationships and Related Transactions, and Director Independence—Intercorporate Service Agreements.*

The compensation of our NEOs included in the tables below is established by Enbridge as described above. We selected our top three most highly compensated executives (other than our principal executive officer and our principal financial officer) based on current expectations regarding the amount of time such executives will devote to us and services related to our business. We have included in the following tables the full amount of compensation and related benefits provided for each of the NEOs for 2013, 2012 and 2011, together with the budgeted estimate of the approximate time spent by each NEO on EEP's behalf and the approximate amount of compensation cost allocated to EEP for the years ended December 31, 2013, 2012 and 2011, as applicable. Since the amount of NEO compensation allocated to EEP is based on estimates of time spent on EEP's behalf by the particular NEO, the compensation amounts allocated to EEP may not exactly reflect the amount of time that a certain NEO devoted to EEP's business. We are a newly established partnership that was formed in May 2013. While no specific amounts of such compensation were allocated to us for 2013, 2012 or 2011, the financial statements of Midcoast Operating, L.P., our predecessor for accounting purposes, include an allocation of NEO compensation.

SUMMARY COMPENSATION TABLE

Name and[1] Principal Position (a)	Year (b)	Salary ($) (c)	Stock Awards[1] ($) (e)	Option Awards[2] ($) (f)	Non-Equity Incentive Plan Compensation[3] ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation[4] ($) (i)	Total ($) (j)	Approximate Percentage of Time Devoted to Enbridge Energy Partners, L.P. (%)	Approximate Amount Allocated to Enbridge Energy Partners, L.P. ($)
Mark A. Maki	2013	383,336	429,868	338,047	220,170	(236,000)	34,496	1,169,917	75	808,311
Principal Executive	2012	344,475	590,857	289,938	183,630	813,000	34,246	2,256,146	95	1,896,178
Officer and Director	2011	336,588	535,317	237,103	216,340	781,000	33,996	2,140,344	86	1,974,238
Terrance L. McGill	2013	380,391	462,395	439,139	188,120	90,000	35,510	1,595,555	74	1,396,922
President and Director	2012	367,660	712,584	415,786	177,160	371,000	35,822	2,080,012	90	1,809,538
	2011	366,309	734,843	435,372	237,060	442,000	35,853	2,251,437	86	2,080,741
Stephen J. Neyland[5] ...	2013	257,788	272,116	200,840	134,610	3,000	34,496	902,850	90	780,931
Vice President—	2012	241,198	249,187	163,217	129,750	162,000	33,532	978,884	90	824,613
Finance	2011	234,998	151,454	125,248	139,150	157,000	33,496	841,346	86	763,286
John A. Loiacono	2013	260,733	259,101	206,463	115,430	(27,000)	35,510	850,237	100	850,237
Vice President—	2012	251,383	330,999	184,503	100,290	196,000	35,610	1,098,785	100	1,098,785
Commercial Activities	2011	243,196	302,139	162,415	157,370	233,000	35,763	1,133,883	100	1,133,883
Kerry C. Puckett	2013	254,996	243,797	203,528	115,370	1,000	34,680	853,371	100	853,371
Vice President—	2012	244,386	365,813	181,120	98,920	188,000	33,884	1,112,123	100	1,112,123
Engineering and Operations Gathering & Processing	2011	231,962	322,516	160,962	130,450	200,000	33,538	1,079,428	100	1,079,428

(1) The compensation expense associated with Performance Stock Units, or PSUs, for each NEO, that are reflected in this column represent one-third of the market value for each year the PSUs are outstanding and are measured based on the number of respective units granted, dividends reinvested, cliff-vested, the actual or forecast performance multiplier with respect to the PSUs, and the market value or payout amount at the end of each period. For example, 2013 includes one-third of the market values for PSUs issued in 2013, 2012 and 2011. In 2013, the compensation expense recorded for PSUs granted in 2013, 2012 and 2011 include performance multipliers for the respective years, which are estimated to be 2.0 based upon the expected or achieved levels of performance in relation to established targets for each year. For years prior to the year a

payout is made, a performance multiplier is forecast based upon the progress made in attaining the established performance criteria unless the actual multiplier has been determined. Refer also to *Footnote 3* of the *Grants of Plan—Based Awards* table for additional discussion regarding the PSUs. The market value for each PSU grant represents the weighted average closing price of an Enbridge common share as quoted on the NYSE for the USD denominated PSUs for the 20 consecutive days prior to the beginning of the new year. PSUs granted for 2013, 2012 and 2011 were denominated in USD. The PSUs were granted on January 1, 2013, 2012 and 2011, respectively. The actual payout amounts for the 2011 PSUs that vested on December 31, 2013 were based on average share prices of $41.56 USD. Compensation expense as reported in the Summary Compensation Table above for Stock Awards has been determined using the following assumptions:

	2013	2012	2011	2010[(a)]	2009[(a)]
End of Period Market Value USD	$41.65	$42.27	$35.75	$27.71	$22.41
Performance multiplier	N/A	N/A	N/A	N/A	N/A
Assumed performance multiplier	2.00	2.00	2.00	2.00	2.00

(a) Where appropriate, prices adjusted for the May 2011 Enbridge stock split.

(2) Under the authoritative accounting provisions for share-based payments, the annual expenses for option awards that are granted under the Enbridge Incentive Stock Option Plan (2007), or ISOP, and the PSOP are determined by computing the fair value of the options on the grant date using the Black-Scholes option pricing model. The following assumptions were used in computing the fair value of the options on the grant date for the respective option pricing model employed and the indicated year:

	ISOP		
Assumption	**2013**	**2012**	**2011**
Expected option term in years	6	6	6
Expected volatility	19.97%	22.80%	22.40%
Expected dividend yield	2.77%	2.95%	3.41%
Risk-free interest rate	1.05%	1.17%	2.80%

The fair value of options granted as computed using the above assumptions is expensed over the shorter of the vesting period for the options and the period to early retirement eligibility. The exercise price and fair value information for all option grants are in USD as set forth in the table below.

	ISOP		
	2013	**2012**	**2011**
Vesting period in years	4	4	4
Exercise price in USD	$43.84	$38.65	$28.99
Option fair value on grant date in USD	$ 6.26	$ 6.11	$ 5.11

(3) Non-equity incentive plan compensation represents awards that are paid in February of each year for amounts that are earned in the immediately preceding fiscal year under the Enbridge STIP as discussed in the above Compensation Discussion and Analysis. The Non-Equity Incentive Plan Compensation for Messrs. Maki, Neyland, Loiacono and Puckett in 2013 includes an additional amount received during 2013 that was awarded for exceptional performance and contribution to Enbridge and the Partnership.

(4) The table which follows labeled "All Other Compensation" sets forth the elements comprising the amounts presented in this column.

(5) The compensation expense associated with the Restricted Stock Units, or RSU's with respect to Mr. Neyland are reflected in column (e), Stock Awards, and represent one-third of the market value for each year the RSUs are outstanding. The RSUs are measured based on the number of respective units granted, dividends reinvested, cliff-vested, and the market value or payout amount at the end of each period. For example, 2012 and 2011 include one-third of the market values for the RSUs issued in 2010, while 2011 would also include one-third of the market value for RSUs issued in 2009. RSUs do not have performance multipliers used in determining the payout amount. For years prior to the year a payout is made, a performance multiplier is forecast based upon the progress made in attaining the established performance criteria unless the actual multiplier has been determined. The market value for the RSU grant represents the weighted average closing price of an Enbridge common share as quoted on the NYSE for the USD denominated RSUs for the 20 consecutive days prior to the end of the performance period. The RSUs granted to Mr. Neyland for 2009 and 2010 were denominated in only USD. The actual payout amounts for the 2009 RSUs that vested on November 30, 2011 and the 2010 RSUs that vested on November 30, 2012 were based on average share prices of $34.57 USD and $39.39 USD, respectively.

ALL OTHER COMPENSATION
(For the years ended December 31, 2013, 2012 and 2011)

Name	Year	Flexible Benefits[1] $	401(k) Matching Contributions[2] $	Other Benefits[3] $	Total
Mark A. Maki	2013	20,000	12,750	1,746	34,496
	2012	20,000	12,500	1,746	34,246
	2011	20,000	12,250	1,746	33,996
Terrance L. McGill	2013	20,000	12,750	2,760	35,510
	2012	20,000	12,500	3,322	35,822
	2011	20,000	12,250	3,603	35,853
Stephen J. Neyland	2013	20,000	12,750	1,746	34,496
	2012	20,000	11,786	1,746	33,532
	2011	20,000	11,750	1,746	33,496
John A. Loiacono	2013	20,000	12,750	2,760	35,510
	2012	20,000	12,288	3,322	35,610
	2011	20,000	12,160	3,603	35,763
Kerry C. Puckett	2013	20,000	12,740	1,940	34,680
	2012	20,000	11,944	1,940	33,884
	2011	20,000	11,598	1,940	33,538

(1) Flexible benefits for our NEOs represent a perquisite allowance that is paid in cash as additional compensation.

(2) Our NEOs that participate in the Enbridge Employee Services, Inc. Savings Plan, referred to as the 401(k) Plan, may contribute up to 50% of their base salary, which is matched up to 5% by Enbridge. Both individual and matching contributions are subject to limits established by the Internal Revenue Service. Enbridge contributions are used to purchase Enbridge common shares at market value and employee contributions may be used to purchase Enbridge common shares or 23 designated funds.

(3) Other benefits include parking for our NEOs.

Enbridge does not maintain any compensation plans for the benefit of the NEOs under which equity interests in EEP or Enbridge Management may be awarded. However, Enbridge allocates to EEP a portion of the compensation expense it recognizes in accordance with the authoritative guidance for share-based compensation in connection with recording the fair value of its performance and restricted stock units and outstanding stock options granted to certain of its officers, including the NEOs. The costs EEP is charged, with respect to option grants, represents a portion of the costs determined in accordance with U.S. GAAP. In accordance with terms of the intercorporate services agreement, we reimburse EEP for an allocated portion of these costs.

The PSUs are granted to the NEOs pursuant to the PSUP and stock options are granted pursuant to the ISOP. Awards under these plans provide long-term incentive and are administered by the HRC Committee of Enbridge. Although stock options remain outstanding that were granted under the Enbridge Incentive Stock Option Plan (2002), no further stock options will be granted under this plan. The performance stock units granted in 2011 through 2013 to our NEOs are denominated in USD. The three tables which follow set forth information concerning performance stock units and stock options granted during the year ended December 31, 2013, outstanding at December 31, 2013 and the number of awards vested and exercised during the year ended December 31, 2013 by each of the NEOs.

GRANTS OF PLAN-BASED AWARDS

				Estimated Future Payouts Under Non-Equity Incentive Plan Awards[2]			Estimated Future Payouts Under Equity Incentive Plan Awards[3]			All Other Option Awards: Number of Securities Underlying Options[4] (#) (j)	Exercise or Base Price of Option Awards[4] ($/Sh) (k)	Date Fair Value of Stock and Option Awards[3][4] ($) (l)
Name (a)	Plan Name[1] (b)	Approval Date (b)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)			
Mark A. Maki . . .	PSUP	13-Feb-13	1-Jan-13	—	—	—	2,438	3,900	7,800	—	—	164,853
	ISOP	13-Feb-13	27-Feb-13	—	—	—	—	—	—	63,600	43.84	398,136
	STIP	3-Feb-14	27-Feb-14	—	139,485	278,970	—	—	—	—	—	—
Terrance L. McGill	PSUP	13-Feb-13	1-Jan-13	—	—	—	2,688	4,300	8,600	—	—	181,761
	ISOP	13-Feb-13	27-Feb-13	—	—	—	—	—	—	70,150	43.84	439,139
	STIP	3-Feb-14	27-Feb-14	—	153,562	307,123	—	—	—	—	—	—
Stephen J. Neyland	PSUP	13-Feb-13	1-Jan-13	—	—	—	1,438	2,300	4,600	—	—	97,221
	ISOP	13-Feb-13	27-Feb-13	—	—	—	—	—	—	41,050	43.84	256,973
	STIP	3-Feb-14	27-Feb-14	—	88,272	176,544	—	—	—	—	—	—
John A. Loiacono	PSUP	13-Feb-13	1-Jan-13	—	—	—	1,469	2,350	4,700	—	—	99,335
	ISOP	13-Feb-13	27-Feb-13	—	—	—	—	—	—	38,150	43.84	238,819
	STIP	3-Feb-14	27-Feb-14	—	88,780	177,559	—	—	—	—	—	—
Kerry C. Puckett	PSUP	13-Feb-13	1-Jan-13	—	—	—	1,438	2,300	4,600	—	—	97,221
	ISOP	13-Feb-13	27-Feb-13	—	—	—	—	—	—	37,250	43.84	233,185
	STIP	3-Feb-14	27-Feb-14	—	86,894	173,788	—	—	—	—	—	—

(1) The abbreviated plan names are defined as follows:

a. PSUP refers to the Enbridge Performance Stock Unit Plan (2007), an equity-based incentive plan.

b. ISOP refers to the Enbridge Incentive Stock Option Plan (2007), a stock option plan.

c. STIP refers to the Enbridge Short Term Incentive Plan (2006), a non-equity performance-based incentive plan.

(2) The estimated future payouts under non-equity incentive award plans represent awards under the Enbridge STIP as presented above in the Compensation Discussion and Analysis under the section labeled Short-Term Incentive Plan.

(3) Our NEOs are eligible to receive annual grants of PSUs, under the PSUP, an equity-based, long-term incentive plan, administered by a committee of the board of directors of Enbridge. The initial value of each of these PSUs on the grant date is equivalent to the volume weighted average closing price of one Enbridge common share as quoted on the TSX or NYSE for the 20 trading days immediately preceding the start of the performance period. The initial PSUs granted are increased for quarterly dividends paid during the three-year period on an Enbridge common share that are reinvested in additional PSUs. Awards under the PSUP are paid out in cash at the end of a three-year performance cycle based on: (1) an EPS target for Enbridge based on the long range plan of the organization and (2) the P/E Ratio of an Enbridge common share relative to a defined group of peer organizations established in advance by a committee of the board of Enbridge. Payments under the PSUP may be increased up to 200% of the original award when Enbridge exceeds the established targets. If Enbridge fails to meet threshold performance levels, no payments are made under the PSUP. Notional dividends are paid on the PSUs which are invested in additional PSUs at the then current market price for one share of Enbridge common stock, which are not included in the estimated future payout amounts, but have been included in the compensation associated with stock awards in the Summary Compensation Table. Enbridge does not issue any common shares in connection with the PSUP.

The threshold at which PSUs are paid out represents 62.5% of the number of PSUs initially granted increased by additional PSUs resulting from reinvested dividends and is the lowest level at which PSUs will be paid out based on the performance criteria discussed above. The target level at which PSUs are issued represents 100% of the number of PSUs initially granted increased by additional PSUs resulting from reinvested notional dividends and attainment of the established performance criteria. The maximum level at which PSUs may be issued is 200% of the number of PSUs initially granted increased by additional PSUs resulting from reinvested dividends and may occur when Enbridge exceeds the established performance criteria. PSUs vest at the end of a three year performance period that begins on January 1 of the year granted and during the term the PSUs are outstanding, a liability and expense are recorded by Enbridge based on the number of PSUs outstanding and the current market price of an Enbridge common share with an assumed performance multiplier that is determined quarterly based on progress towards achieving the established performance criteria, until the end of the performance period at which point the performance multiplier is known. The grant date fair value for each PSU granted to each of our NEOs in 2013 was $42.27 USD, representing the volume weighted average closing price of one Enbridge common share as quoted on the NYSE for the 20 trading days immediately preceding the start of the performance period that began on January 1, 2013.

(4) The ISOP is administered by a committee of the Enbridge board of directors. If an option is awarded at a time when a blackout period is in effect, the grant price of the option will be set on the sixth trading day following the termination of the blackout period, and will be based on the weighted average trading price of an Enbridge common share on the NYSE for the five trading days immediately preceding. If an option is granted when a blackout period is not in effect, the exercise price may not be less than 100% the fair market value as at grant date. During 2013, each of the NEOs received grants of Enbridge incentive stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The exercise price of the incentive stock options at the time of grant was $43.84 USD for our NEOs.

The amounts included as the grant date fair value for the 2013 incentive stock option awards represent the amount determined by computing the fair value of the options in accordance with the authoritative guidance for share-based payments on the grant date using the Black-Sholes option pricing model with the following assumptions:

- 6 years expected term;
- 19.97% expected volatility;
- 2.77% expected dividend yield; and
- 1.05% risk free interest rate

The fair value of options granted as computed using these assumptions is $6.26 USD. The grant date fair value is expensed over the shorter of the vesting period for the options, generally four years, and in the year granted for employees age 55 and over and eligible for early retirement. Mr. McGill was aged 55 or over and eligible for early retirement as of the grant date and, as a result, the grant date fair value of options he was awarded is expensed in the year granted.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

	Option Awards				Stock Awards	
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable[1] (c)	Option Exercise Price[2] ($) (e)	Option Expiration Date[1] (f)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[3] (#) (i)	Equity Incentive Plan Awards: Market or Payout of Value Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
Mark A. Maki	—	63,600	43.84	27-Feb-23	4,013	334,309
	15,413	46,237	38.65	2-Mar-22	4,712	392,538
	38,200	38,200	28.99	14-Feb-21		
	25,500	8,500	21.97	16-Feb-20		
	45,700	—	15.80	25-Feb-19		
	5,200	—	20.17	19-Feb-18		
Terrance L. McGill	—	70,150	43.84	27-Feb-23	4,425	368,597
	17,013	51,037	38.65	2-Mar-22	5,242	436,643
	42,600	42,600	28.99	14-Feb-21		
	36,750	12,250	21.97	16-Feb-20		
	99,000	—	15.80	25-Feb-19		
	99,000	—	20.17	19-Feb-18		
Stephen J. Neyland	—	41,050	43.84	27-Feb-23	2,367	197,157
	399	5,573	38.65	2-Mar-22	3,812	317,559
	9,376	23,752	38.65	2-Mar-22		
	11,150	22,300	28.99	14-Feb-21		
	3,850	3,850	21.97	16-Feb-20		
	2,750	—	15.80	25-Feb-19		
John Loiacono	—	38,150	43.84	27-Feb-23	2,418	201,443
	9,300	27,900	38.65	2-Mar-22	2,859	238,169
	25,500	25,500	28.99	14-Feb-21		
	13,800	4,600	21.97	16-Feb-20		
	28,700	—	15.80	25-Feb-19		
Kerry Puckett	—	37,250	43.84	27-Feb-23	2,367	197,157
	8,950	26,850	38.65	2-Mar-22	2,806	233,758
	22,300	22,300	28.99	14-Feb-21		
	17,850	5,950	21.97	16-Feb-20		
	6,331	—	15.80	25-Feb-19		
	35,969	—	15.80	25-Feb-19		
	7,085	—	20.17	19-Feb-18		
	40,715	—	20.17	19-Feb-18		

(1) Each ISO award has a 10-year term and vests pro-rata as to one fourth of the option award beginning on the first anniversary of the grant date; thus the vesting dates for each of the option awards in this table can be calculated accordingly. As an example, for Mr. Maki's grant that expires on February 14, 2021, the grant date would be 10 years prior or February 14, 2011 and as a result, the remaining unexercisable amounts become fully vested on February 14, 2015 representing four years following the grant date.

(2) Where appropriate, all exercise prices and valuation prices prior to 2011 have been adjusted for the April 2011 Partnership stock split and Enbridge's May 2011 stock split.

(3) The unearned common shares, units or other rights that have not vested under stock awards represent PSUs that have not yet reached the end of their term. The PSUs become vested upon achieving the established performance criteria discussed in Footnote 3 of the *Grants of Plan-Based Awards* table, at the end of the term. The amounts represented in the column are the number of units that have not vested at the weighted average noon rate for 20 trading days at year end 2013 of one Enbridge common share on the NYSE at $41.65. The market or payout values presented assume a performance multiplier of 2.0 for PSUs granted in 2013 and 2012, which amounts represent the maximum level attainable based on forecasts of performance at December 31, 2013.

OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting[1] (#) (d)	Value Realized on Vesting[2] ($) (e)
Mark A. Maki	—	—	6,552	544,607
Terrance L. McGill	—	—	6,770	562,761
Stephen J. Neyland	5,000	127,837	3,494	290,457
John A. Loiacono	12,800	291,649	3,931	326,764
Kerry C. Puckett	9,000	234,760	3,494	290,457

(1) The number of common shares acquired on vesting for stock awards represents the number of PSUs issued in 2011 and the related dividends paid that were used to acquire additional PSUs, all of which matured on December 31, 2013. As discussed in Footnote 3 of the *Grants of Plan-Based Awards* table, no common shares are issued with respect to the PSUs that become vested; rather, cash is paid in an amount based on the value of an Enbridge common share at the maturity date and the level of achievement of the established performance goals. The payout for the PSUs granted in 2011 is expected to occur on or about March 14, 2014.

(2) The value realized on vesting is determined based on the final value of an Enbridge common share of $41.56 USD. In each case the common share price is multiplied by a 2.0 performance factor multiplied by the number of PSUs for the PSUs that matured on December 31, 2013.

Pension Plan

Enbridge sponsors two qualified pension plans, the Retirement Plan for the Employees of Enbridge Inc. and Affiliates, or EI RPP, and the Enbridge Employee Services, Inc. Employees' Pension Plan, or QPP. These plans provide defined pension benefits, and cover employees in Canada and the United States, respectively. Both plans are non-contributory. Enbridge also sponsors supplemental nonqualified retirement plans in both Canada, referred to as EI SPP, and the United States, referred to as US SPP, which provide defined pension benefits for the NEOs in excess of the tax-qualified plans' limits. Mr. Maki is the only NEO that has pension credits from the EI RPP and EI SPP for prior years of service when he was in an Enbridge executive leadership role in Canada. We collectively refer to the EI RPP, the QPP, the EI SPP and the US SPP as the Pension Plans. Defined pension benefits under the grandfathered benefit of the Pension Plans are based on the employees' years of service and average final remuneration with an offset for Social Security benefits, while cash balance benefits provide annual pay credits, based on the employees' pensionable pay, age and years of service, and interest credits to notional member accounts.

For service prior to becoming a senior management employee, there are different pension benefits depending on an employee's hire date with Enbridge. Employees hired before January 1, 2002 have grandfathered benefits; the Pension Plans provide a yearly pension payable in the normal form (60% joint and survivor) equal to: (a) 1.6% of the average of the participant's highest annual salary during three consecutive years out of the last ten years of credited service multiplied by (b) the number of credited years of service. The pension is offset, after age 65, by 50% of the participant's Social Security benefit, pro-rated by years in which the participant has both credited service and Social Security coverage. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the United States and Canadian plans are indexed at 50% of the annual increase in the United States and Canadian consumer price index, respectively. For employees hired after January 1, 2002, the Pension Plans provide cash balance benefits.

For service while a senior management employee, the Pension Plans provide a yearly pension payable in the normal form (60% joint and survivor) equal to: (a) 2% of the sum of (i) the average of the participant's highest annual base salary during three consecutive years out of the last ten years of credited service and (ii) the average of the participant's three highest annual performance bonus periods, represented in each period by 50% of the actual bonus paid, in respect of the last five years of credited service, multiplied by (b) the number of credited years of service. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Pension Plan are indexed at 50% of the annual increase in the consumer price index. All NEOs are currently senior management employees.

The table below illustrates the total annual pension entitlements at December 31, 2013 assuming the eligibility requirements for an unreduced pension have been satisfied. We have converted pension payable in CAD into USD at the rate of $1.0299 CAD = $1.00 USD, the exchange rate for the period ended December 31, 2013. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	4.70% at year end 2013
Salary increases	None
Inflation	2.50% per year
Retirement age	Age when first eligible for an unreduced pension[(1)]
Terminations	None
Mortality Rates:	
Pre-retirement	None
Post-retirement	PPA generational annuitant and non-annuitant tables (RP-2000 with generational mortality improvements)

(1) This is age 60 for all executives except for Mr. Maki, who is eligible for an unreduced pension at age 55.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service[(1)] (#) (c)	Present Value of Accumulated Benefit ($) (d)
Mark A. Maki	EI RPP	1.92	82,000
	EI SPP	1.92	152,000
	US QPP	25.40	1,570,000
	US SPP	25.40	1,140,000
Terrance L. McGill	US QPP	11.50	231,000
	US SPP	11.83	1,789,000
Stephen J. Neyland	US QPP	11.50	181,000
	US SPP	9.00	385,000
John A. Loiacono	US QPP	11.50	191,000
	US SPP	10.75	645,000
Kerry C. Puckett	US QPP	11.50	175,000
	US SPP	9.42	586,000

(1) For all NEOs, with the exception of Mr. Maki, US SPP service represents years of service as a senior management employee. Mr. Maki has 14.00 years of service as a senior management employee.

Director Compensation

As a partnership, we are managed by our General Partner. The board of directors of our General Partner perform for us the functions of a board of directors of a business corporation. We are allocated 100% of the director compensation of these board members. Enbridge employees who are members of the boards of directors of our General Partner do not receive any additional compensation for serving in those capacities.

Directors of our General Partner who are not officers or employees of our General Partner or its affiliates receive compensation as "non-employee directors," which is an annual retainer value equal to $115,000 payable in cash. The chairman of the board of directors of our General Partner receives an additional annual cash retainer equal to $20,000. In addition, the chair of the Audit, Finance and Risk Committee receives an additional annual cash retainer equal to $15,000. The chair of the Conflicts Committee will receive $5,000 per assignment, plus additional amounts to be paid at the discretion of the board of directors of our General Partner depending on the complexity of the project and the time involved.

The Corporate Governance Guidelines provide an expectation that independent directors will hold a personal investment in us of at least two times the annual board retainer, which, based on the current annual retainer would equal $230,000 (i.e., 2 X $115,000 = $230,000). Directors would be expected to achieve the foregoing level of equity ownership by the later of October 10, 2018 or five years from the date he or she became a director. All of our independent directors are in compliance with this requirement.

DIRECTOR COMPENSATION

Name (a)	**Fees Earned or Paid in Cash(1) ($) (b)**
Dan A. Westbrook *Chairman of the Board*	65,579
J. Herbert England *Audit, Finance & Risk Committee Chairman*	63,205

(1) Both directors were elected in October 2013, thus the fees presented above cover the period from October 10, 2013 through December 31, 2013. Additionally, the first quarter 2014 retainer for each director was paid before December 31, 2013 and is included in the amounts shown above.

Each director is indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law and will be reimbursed for all expenses incurred in attending to his or her duties as a director.

COMPENSATION REPORT OF THE BOARD OF DIRECTORS

The Board of Directors of Midcoast Holdings, L.L.C has reviewed and discussed the Compensation Discussion and Analysis section of this report with management and, based on that review and discussion, has recommended that the Compensation Discussion and Analysis be included in this report.

/s/ Mark A. Maki	/s/ Terrance L. McGill
Mark A. Maki	Terrance L. McGill
Principal Executive Officer and Director	*President and Director*
/s/ Dan A. Westbrook	/s/ J. Herbert England
Dan A. Westbrook	J. Herbert England
Director	*Director*
/s/ C. Gregory Harper	/s/ John A. Crum
C. Gregory Harper	John A. Crum
Director	*Director*
/s/ James G. Ivey	/s/ Edmund P. Segner III
James G. Ivey	Edmund P. Segner III
Director	*Director*

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 information as of February 14, 2014 with respect to persons known to us to be the beneficial owners of more than 5% of any class of the Partnership's units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent of Class
Enbridge Energy Partners, L.P[1].	Class A common units	1,335,056	5.9
1100 Louisiana St., Suite 3300	Subordinated units	22,610,056	100
Houston, TX 77002	General Partner units	922,859	100
Oppenheimer Funds Inc.	Class A common units	4,089,018	18.1
225 Liberty Street			
New York, NY 10281-1008			
Oppenheimer SteelPath MLP Income Fund	Class A common units	3,039,729	13.4
6803 S. Tucson Way			
Centennial, CO 80112			
Neuberger Berman L.L.C.[2]	Class A common units	1,969,425	8.7
605 Third Avenue			
New York, NY 10158			
ClearBridge Investments, L.L.C	Class A common units	1,300,000	5.8
620 8th Avenue			
New York, NY 10018			

(1) As of February 14, 2014, EEP directly held 1,335,056 Class A common units and 22,610,056 Subordinated units; 922,859 general partner units were held by Midcoast Holdings, a wholly owned subsidiary of EEP.

(2) Neuberger Berman Group L.L.C. reported shared voting power as to 1,951,375 shares and shared dispositive power as to 1,965,425 shares in its Schedule 13G, filed February 12, 2014

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 14, 2014 with respect to each class of our units beneficially owned by the NEOs and directors and executive officers of Midcoast Holdings as a group:

	Midcoast Energy Partner, L.P.		
Name	Title of Class	Number of of Class [1]	Percent of Class
Dan A. Westbrook[2]	Class A common units	5,000	*
J. Herbert England	Class A common units	5,000	*
John A. Crum	Class A common units	—	*
James G. Ivey	Class A common units	—	*
Edmund P. Segner III	Class A common units	—	*
C. Gregory Harper	Class A common units	—	*
Mark A. Maki	Class A common units	14,000	*
Terrance L. McGill	Class A common units	20,000	*
John A. Loiacono	Class A common units	5,000	*
Stephen J. Neyland	Class A common units	4,700	*
Kerry C. Puckett	Class A common units	5,000	*
All executive officers, directors and nominees as a group (17 persons)	Class A common units	58,800	*

* Less than 1%.

(1) Unless otherwise indicated, each beneficial owner has sole voting and investment power with respect to all of the Class A common units attributed to him or her.

(2) Mr. Westbrook is the indirect owner of these units, which are held by the Westbrook Trust.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table provides information as of December 31, 2013 with respect to Class A common units that may be issued under the 2013 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or our LTIP:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[1]	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans[2]
Equity compensation plans approved by security holders	N/A	N/A	3,750,000
Equity compensation plans not approved by security holders	—	—	—
Total			3,750,000

(1) We have not previously granted equity incentive awards in us to any person pursuant to the LTIP

(2) Reflects the Class A common units available for issuance pursuant to the LTIP

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

As of December 31, 2013, Enbridge Energy Partners owned 1,335,056 Class A common units and 22,610,056 subordinated units representing a 51.9% limited partner interest in us. In addition, our General Partner owns 922,859 general partner units representing a 2% general partner interest in us.

Administrative and Workforce Related Services

Enbridge and its affiliates provide management, administrative, operational and workforce related services to us. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the administrative and operational services charged to us.

We do not directly employ any of the individuals responsible for managing or operating our business. We have historically obtained managerial, administrative and operational services from EEP's general partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, EEP, Enbridge Management and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse EEP's general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us. In connection with the Offering, we entered into an intercorporate services agreement with EEP pursuant to which we agreed upon certain aspects of our relationship with EEP, including the provision by EEP or its affiliates to us of certain administrative services and employees, our agreement to reimburse EEP or its affiliates for the cost of such services and employees and certain other matters.

Intercorporate Service Agreements

On November 13, 2013, in connection with the closing of the Offering, the Partnership entered into an Intercorporate Service Agreement with EEP, pursuant to which EEP will provide the Partnership with the following services:

- executive, management, business development, administrative, legal, human resources, records and information management, public affairs, investor relations, government relations and computer support services;
- accounting and tax planning and compliance services, including preparation of financial statements and income tax returns, unitholder tax reporting and audit and treasury services;

- strategic insurance advice, planning and claims management and related support services, and arrangement of insurance coverage as required;
- facilitation of capital markets access and financing services, cash management and related banking services financial structuring and advisory services, as well as credit support for the Partnership's subsidiaries and affiliates on an as-needed basis for projects, transactions or other purposes;
- operational and technical services, including integrity, safety, environmental, project management, engineering, fundamentals analysis and regulatory, and pipeline control and field operations; and
- such other services as the Partnership may request.

Under the Intercorporate Services Agreement, the Partnership will reimburse EEP and its affiliates for the costs and expenses incurred in providing such services to the Partnership. The allocation methodology under which the Partnership will reimburse EEP and its affiliates for the provision of general administrative and operational services to Midcoast Operating will not differ from what Midcoast Operating was allocated historically under its prior services agreements with Enbridge and certain of its affiliates that were in effect prior to the Intercorporate Services Agreement. However, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually. Based on the Partnership's 39% interest in Midcoast Operating, the reduction in amounts payable for general and administrative services attributable to the Partnership will be approximately $9.8 million annually and will continue for the term of the agreement.

The total amount incurred by us, through EEP, per the MEP only cost centers, for services received pursuant to the general and administrative services agreement for the years ended December 31, 2013, 2012 and 2011 was $176.9 million, $207.3 million and $182.1 million, respectively. These amounts were settled through "Net cash contributions from partners" as reflected on our Consolidated Statements of Partners' Capital and amounts settled after November 12, 2013 were settled through cash. The following table presents the affiliate amounts reflected in our Consolidated Statements of Income by category as follows:

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of $6.8 million, $6.4 million and $6.0 million as of December 31, 2013, 2012 and 2011, respectively, that we recorded as additions to "Property, plant and equipment, net" on our consolidated statements of financial position.

Insurance Allocation Agreement

We participate in the comprehensive insurance program that is maintained by Enbridge for its benefit and the benefit of its subsidiaries. On November 13, 2013, in connection with the closing of the Offering, we entered into an Amended and Restated Allocation Agreement, or the Insurance Allocation Agreement, by and among the Partnership, Enbridge, EEP and Enbridge Income Fund Holdings Inc., in order to participate in the comprehensive insurance program that is maintained by Enbridge for it and its subsidiaries. Under this agreement, in the unlikely event that multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis.

Affiliate Revenues and Purchases

We purchase natural gas, NGLs and crude oil from third parties, which subsequently generate operating revenues from sales to Enbridge and its affiliates. The sales to Enbridge and its affiliates are presented in "Operating revenue - affiliate" on our consolidated statements of income. These transactions are entered into at the market price on the date of sale. Included in our results for the years ended December 31, 2013, 2012 and 2011 are operating revenues from sales to Enbridge and its affiliates of $213.1 million, $396.2 million and $323.0 million, respectively.

We also purchase natural gas, NGLs and crude oil from Enbridge and its affiliates for sale to third parties at market prices on the date of purchase. The purchases of natural gas, NGLs and crude oil from Enbridge and its affiliates are presented in "Cost of natural gas and natural gas liquids—affiliate" on our consolidated statements of income. Included in our results for the years ended December 31, 2013, 2012 and 2011 are costs for natural gas, NGLs and crude oil purchases from Enbridge and its affiliates of $119.6 million, $289.5 million and $202.0 million, respectively.

Routine purchases and sales with affiliates are settled monthly through our treasury function at terms that are consistent with third-party transactions. Routine purchases and sales with affiliates that have not yet been settled are included in "Due from general partner and affiliates" and "Due to general partner and affiliates" on our consolidated statements of financial position.

Related Party Transactions with Joint Venture

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together are constructing a 580 mile NGL intrastate transportation pipeline and a related NGL gathering system that was placed into service in the fourth quarter of 2013. Our equity investment in the Texas Express NGL system at December 31, 2013, 2012 and 2011 was $371.3 million, $183.7 million and $10.7 million, respectively, which is included on our consolidated statements of financial position in "Equity investment in joint venture."

Our logistics and marketing business has made commitments to transport up to 120,000 barrels per day, or bpd, of NGLs on the Texas Express NGL system from 2013 to 2023.

Partners' Capital Transactions

Prior to the Offering, our capital accounts were comprised of a 99.999% limited partner interest that was owned entirely by EEP and a 0.001% general partner interest that was owned by the Midcoast OLP GP, L.L.C (f/k/a Enbridge Midcoast Holdings, L.L.C.), or the OLP GP, a wholly owned subsidiary of EEP. After the Offering, partners' capital accounts consist of general partner interests held by our General Partner, and limited partner interests held by EEP and the public. We paid cash distributions to EEP and OLP GP totaling $302.2 million and $342.4 million for the fiscal years ended December 31, 2012 and 2011, respectively, and $247.7 million for the portion of fiscal year 2013 prior to the Offering. No cash distributions were made to our partners in the period after the Offering through December 31, 2013. These amounts were settled through "Distributions to partners" as reflected on our consolidated statements of cash flows.

Conflicts of Interest

Under our partnership agreement, our General Partner has a duty to manage us in a manner it believes is in the best interests of the Partnership. However, because our General Partner is a wholly owned subsidiary of EEP, the officers and directors of our General Partner also have a duty to manage the business of our General Partner in a manner that they believe is in the best interests of EEP. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our General Partner and its affiliates, including EEP, on the other hand. In addition, our General Partner may determine to manage our business in a way that directly benefits EEP's businesses, rather than indirectly benefitting EEP solely through its ownership interests in us. All of these actions are permitted under our partnership agreement and will not be a breach of any duty (fiduciary or otherwise) of our General Partner. As permitted by Delaware law, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our General Partner with contractual standards governing the duties of the General Partner and contractual methods of resolving conflicts of interest. The effect of these provisions is to restrict the remedies available to our unitholders for actions that might otherwise constitute breaches of our General Partner's fiduciary duties. Our partnership agreement also provides that affiliates of our General Partner, including EEP and Enbridge, are not restricted from competing with us, and neither our General Partner nor its affiliates have any obligation to present business opportunities to us.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013 and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. The Receivables Agreement and the transactions contemplated thereby were approved by a special committee of the board of directors of Enbridge Management, which prior to the Offering, effectively managed the business of the Predecessor through its management of EEP's business. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of those of ours subsidiaries and other subsidiaries of EEP that are parties thereto up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement. EEP and the Partnership each act in an administrative capacity as collection agent on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. Prior to the amendment to the Receivables Agreement on December 2, 2013 EEP was the sole collection agent on behalf of the Enbridge subsidiary. EEP and the Partnership have no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative – affiliate" expense in our consolidated statements of income. For the year ended December 31, 2013, the loss stemming from the discount on the receivables sold was not material. For the year ended December 31, 2013, we derecognized and sold $1,566.7 million, of accrued receivables to the Enbridge subsidiary. For the year ended December 31, 2013, the cash proceeds were $1,566.3 million, which was remitted to EEP or the Partnership, as applicable, in their capacity as collection agent, through our centralized treasury system. As of December 31, 2013, $273.6 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

Allocated Interest

EEP incurs borrowing cost on our behalf, which we recognize to the extent we are able to capitalize such costs to our construction related projects. The interest cost we incur is directly offset by the amount of interest we capitalize on outstanding construction projects.

Our interest cost of the year ended December 31, 2013, 2012 and 2011 is detailed below:

	December 31,		
	2013	2012	2011
		(in millions)	
Operating and maintenance—affiliate	$ 78.7	$110.1	$100.5
General and administrative—affiliate	98.2	97.2	81.6
Total	$176.9	$207.3	$182.1

Derivative Transactions

We have related party derivative transactions executed on behalf of EEP that were contracted through the Partnership prior to the Offering and are allocated to EEP. These transactions were contracted to hedge the forward price of EEP's crude oil length inherent to the operation of pipelines and to hedge EEP's interest payments of variable rate debt obligations that are sensitive to changes in interest rates. These hedges create a fixed sales price for crude oil that EEP will receive in the future and lock in the interest rate on EEP's anticipated future debt. Subsequent to the Offering, these transactions were re-contracted through EEP and will no longer be allocated from the Partnership. These transactions are included as part of Note 14. *Derivative Financial Instruments and Hedging Activities.*

For further discussion of these and other related party transactions, refer to Note 12. *Related Party Transactions* in the consolidated financial statements of this Annual Report on Form 10-K.

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our General Partner as appropriate. The board of directors then determines whether it is advisable to constitute a special committee of independent directors to evaluate the proposed transaction. If a special committee is appointed, the committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the special committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair to us and all of our unitholders.

Potential transactions with related persons that are not financially significant so as to require review by the board of directors are disclosed to the President of our General Partner and reviewed for compliance with the Enbridge Statement on Business Conduct. The President may also consult with legal counsel in making such determination. If a related person transaction occurred and was later found not to comply with the Statement on Business Conduct, the transaction would be reported to the board of directors for further review and ratification or remedial action.

During 2013, we had the following "related person" transactions (as the term is defined in Item 404 of Regulation S-K):

- An affiliate of Enbridge that provides employee services to the Partnership continued a previously existing employment relationship with Ryan McGill, the son of Terrance L. McGill, one of the named executive officers and a member of the Board of Directors. Mr. McGill is employed in our Houston office as a Gas Supply Representative. During 2013, he received total cash compensation of $97,172.29 and benefits estimated at approximately 32% of his base compensation for a total of $123,822.49.

Item 14. Principal Accountant Fees and Services

The following table sets forth the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP, our principal independent auditors, for each of our last two fiscal years.

	For the year ended December 31,	
	2013	2012
Audit fees[1]	$1,452,000	$ —
Tax fees[2]	219,000	—
Total	$1,671,000	$ —

(1) Audit fees consist of fees billed for professional services rendered for the audit of our consolidated financial statements, reviews of our interim consolidated financial statements, audits of various subsidiaries for statutory and regulatory filing requirements and our debt and equity offerings.

(2) Tax fees consist of fees billed for professional services rendered for federal and state tax compliance for Partnership tax filings and unitholder K-1's.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit, Finance, and Risk Committee of Midcoast Holdings board of directors; however, services up to $50,000 may be approved by the Chairman of the Audit, Finance, and Risk Committee, under the board of directors' delegated authority. All services in 2013 were approved by the Audit, Finance, and Risk Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as a part of this report:

(1) *Financial Statements.*

The following financial statements and supplementary data are incorporated by reference in Part II, Item 8. *Financial Statements and Supplementary Data* beginning on page 89 of this Form 10-K.

a. Report of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

b. Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011.

e. Consolidated Statements of Financial Position as of December 31, 2013 and 2012.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2013, 2012 and 2011.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

All schedules have been omitted because they are not applicable, the required information is shown in the consolidated financial statements or Notes thereto or the required information is immaterial.

(3) *Exhibits.*

Reference is made to the "Index of Exhibits" following the signature page on page 170, which is hereby incorporated into this Item.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MIDCOAST ENERGY PARTNERS, L.P.
(Registrant)

By: Midcoast Holdings, L.L.C.,
as General Partner

By: /s/ Mark A. Maki

Mark A. Maki
Principal Executive Officer

Date: February 18, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 18, 2014 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ Mark A. Maki
Mark A. Maki
Principal Executive Officer and Director

/s/ Terrance L. McGill
Terrance L. McGill
President and Director

/s/ Stephen J. Neyland
Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)

/s/ Noor S. Kaissi
Noor S. Kaissi
Controller
(Principal Accounting Officer)

/s/ J. Herbert England
J. Herbert England
Director

/s/ Dan A. Westbrook
Dan A. Westbrook
Director

/s/ C. Gregory Harper
C. Gregory Harper
Director

/s/ John A. Crum
John A. Crum
Director

/s/ James G. Ivey
James G. Ivey
Director

/s/ Edmund P. Segner III
Edmund P. Segner III
Director

Index of Exhibits

Each exhibit identified below is filed as a part of this annual report. Exhibits included in this filing are designated by an asterisk ("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report pursuant to Item 15(b) of Form 10-K.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Midcoast Energy Partners, L.P., dated May 30, 2013 (incorporated by reference to Exhibit 3.1 of our Registration Statement on Form S-1 (Registration No. 333-189341), initially filed on June 14, 2013, as amended).
3.2	First Amended and Restated Agreement of Limited Partnership of Midcoast Energy Partners, L.P. dated November 13, 2013 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed on November 18, 2013).
4.1	Specimen Unit Certificate for the Class A Common Units (included as Exhibit A to the Form of First Amended and Restated Agreement of Limited Partnership of the Registrant) (incorporated herein by reference to Appendix A of the First Amended and Restated Agreement of Limited Partnership of Midcoast Energy Partners, L.P. under Exhibit 3.1 of our Current Report on Form 8-K, filed on November 18, 2013).
10.1	Contribution, Conveyance and Assumption Agreement by and among Midcoast Energy Partners, L.P., Enbridge Energy Partners, L.P., Midcoast Holdings, L.L.C., Midcoast Operating L.P. and Midcoast OLP GP, L.L.C. dated as of November 13, 2013, (incorporated by reference to Exhibit 10.1 of our of our Current Report on Form 8-K, filed on November 18, 2013).
10.2	Omnibus Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., Midcoast Holdings, L.L.C., Enbridge Energy Partners, L.P. and Enbridge Inc. (incorporated by reference to Exhibit 10.2 of our of our Current Report on Form 8-K, filed on November 18, 2013).
10.3	Credit Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., as Co-Borrower, Midcoast Operating L.P., as Co-Borrower, the subsidiary guarantors party thereto, Bank of America, N.A., as Administrative Agent, Letter of Credit Issuer, Swing Line Lender and lender, and each of the other lenders party thereto (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed on November 18, 2013).
10.4	Intercorporate Services Agreement, dated as of November 13, 2013, by and between EEP and Midcoast Energy Partners, L.P. (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on November 18, 2013).
10.5	Financial Support Agreement, dated as of November 13, 2013, by and between Midcoast Operating, L.P. and EEP (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on November 18, 2013).
10.6	Amended and Restated Allocation Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., Enbridge Inc., EEP and Enbridge Income Fund Holdings Inc., (incorporated by reference to Exhibit 10.6 of our Current Report on Form 8-K, filed on November 18, 2013).
10.7	Working Capital Loan Agreement, dated November 13, 2013, by and between Midcoast Operating, L.P. and EEP (incorporated by reference to Exhibit 10.7 of our Current Report on Form 8-K, filed on November 18, 2013).
10.8	Amended and Restated Agreement of Limited Partnership of Midcoast Operating, L.P., dated as of November 13, 2013 (incorporated by reference to Exhibit 10.8 of our Current Report on Form 8-K, filed on November 18, 2013).

Exhibit Number	Description
10.9	Subordination Agreement dated November 13, 2013 by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., other credit parties from time to time party there to, Enbridge Energy Partners, L.P., and Bank of America, N.A. (incorporated by reference to Exhibit 10.9 of our Quarterly Report on Form 10-Q, filed on December 20, 2013).
*+10.10	Executive Employment Agreement, entered into February 11, 2014, between C. Gregory Harper, the Executive, and Enbridge Employee Services, Inc., effective January 30, 2014.
10.11	Form of Long-Term Incentive Plan of Midcoast Energy Partners, L.P. (incorporated by reference to Exhibit 10.3 to our Registration Statement on Form S-1 (Registration No. 33-189341), initially filed on June 14, 2013, as amended.)
*21.1	Subsidiaries of the Registrant.
*31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema Document.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Maki, certify that:

1. I have reviewed this Annual Report on Form 10-K of Midcoast 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)) 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) Intentionally omitted;

   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: February 18, 2014

By: /s/ Mark A. Maki
Mark A. Maki
Principal Executive Officer
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Neyland, certify that:

1. I have reviewed this Annual Report on Form 10-K of Midcoast 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)) 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) Intentionally omitted;
   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: February 18, 2014

By: /s/ Stephen J. Neyland
Stephen J. Neyland
Vice President, Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.1

CERTIFICATE OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Executive Officer of Midcoast Holdings, L.L.C., the General Partner of Midcoast Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (the "Annual Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 18, 2014

By: /s/ Mark A. Maki
Mark A. Maki
Principal Executive Officer
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.2

CERTIFICATE OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Financial Officer of Midcoast Holdings, L.L.C., the General Partner of Midcoast Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (the "Annual Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 18, 2014

By: /s/ Stephen J. Neyland
Stephen J. Neyland
Vice President, Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)