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, 2015

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 1-10934

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

Delaware	**39-1715850**
(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 ☒

The aggregate market value of the registrant's Class A common units held by non-affiliates computed by reference to the price at which the common equity was last sold on June 30, 2015, was $7,186,696,792.

As of February 12, 2016 the registrant has 262,208,428 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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In this report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our "General Partner." References to "Enbridge" refer collectively to Enbridge Inc., and its subsidiaries other than us. References to "Enbridge Management" refer to Enbridge Energy Management, L.L.C., the delegate of our General Partner that manages our business and affairs.

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 the supply of, forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and NGLs, including the rate of development of the Alberta Oil Sands; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline systems; (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, including those related to Line 6B and any additional fines and penalties and injunctive relief assessed in connection with the crude oil release on that line; (6) changes in or challenges to our tariff rates; (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; and (8) permitting at federal, state and local levels in regards to the construction of new assets.

For additional factors that may affect results, see "Item-1A. Risk Factors" included elsewhere in this Annual Report on Form 10-K, which is available to the public over the Internet at the United States Securities and Exchange Commission's, or the SEC's, website (www.sec.gov) and at our website (www.enbridgepartners.com).

Glossary

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

AEDC	Allowance for equity during construction
AER	Alberta Energy Regulator
AFUDC	Allowance for funds used in construction
Alberta Clipper Pipeline	A 36-inch pipeline that runs from the Canadian international border near Neche, North Dakota to Superior, Wisconsin on our Lakehead system
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)
Bcf/d	Billion cubic feet per day
BLLP	Beaver Lodge Loop Project
Bpd	Barrels per day
Btu	British thermal units
CAA	Clean Air Act of 1970, as amended
CAD	Amount denominated in Canadian dollars
CAO	Corrective Action Order
CAPP	Canadian Association of Petroleum Producers, a trade association representing a majority of our Lakehead system's customers
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFTC	Commodity Futures Trading Commission
CO2e	Carbon Dioxide Equivalent
Credit Facilities	364-Day Credit Facility and the Credit Facility
CWA	Clean Water Act
DBRS	Dominion Bond Rating System
DCF	Discounted Cash Flow
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
EA interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the Eastern Access Projects
East Texas system	Natural gas gathering, treating and processing assets in East Texas that serve the Bossier trend and Haynesville shale areas
Eastern Access Joint Funding Agreement	The funding agreement between Enbridge Energy Partners, L.P. (the Partnership) and Enbridge Energy Company, Inc. (the General Partner) to provide joint funding for the Eastern Access Projects, reflected by the terms of the Series EA partnership interests and the related contribution agreement
Eastern Access Projects	Multiple expansion projects that will provide increased access to refineries in the United States Upper Midwest and in Canada in the provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States.
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EDA	Equity Distribution Agreement
EES	Enbridge Employee Services Inc., a subsidiary of our General Partner
EIA	Energy Information Administration
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.

Enbridge system	Canadian portion of the liquid petroleum mainline system
Enbridge Pipelines	Enbridge Pipelines Inc.
Enterprise Products	Enterprise Products Partners, L.P.
EOSI	Enbridge Operational Services, Inc.
EP Act	Energy Policy Act of 1992
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FSM	Facilities Surcharge Mechanism
GDP	Gross Domestic Product
General Partner	Enbridge Energy Company, Inc., the general partner of the Partnership
GHG PSD	Greenhouse Gas Prevention of Significant Deterioration
HB 500	House Bill 500
HCDP Plants	Hydrocarbon dewpoint control facilities
High Prairie	High Prairie Pipelines L.L.C.
IBES	Institutional Brokers' Estimate System
ICA	Interstate Commerce Act
ISDA®	International Swaps and Derivatives Association, Inc.
IJT	International Joint Tariff
IRS	Internal Revenue Service
i-units	Special class of our limited partner interests
Lakehead system	United States portion of the liquid petroleum Mainline system
LIBOR	London Interbank Offered Rate — British Bankers' Association's average settlement rate for deposits in United States dollars
Light Oil Market Access Program	Several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Project, enhance Enbridge's Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries
M^3	Cubic meters of liquid = 6.2898105 Bbl
Mainline Expansion Joint Funding Agreement	The funding agreement between Enbridge Energy Partners, L.P. (the Partnership) and Enbridge Energy Company, Inc. (the General Partner) to provide joint funding for the U.S. Mainline Expansion projects, reflected by the terms of the Series ME partnership interests and the related contribution agreement
Mainline system	The combined liquid petroleum pipeline operations of our Lakehead system and the Enbridge system, which is 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
Mcf	Thousand cubic feet
MDEQ	Michigan Department of Environmental Quality
MDNRE	Michigan Department of Natural Resources and Environment
MEP	Midcoast Energy Partners, L.P.
MEP General Partner	Midcoast Holdings, L.L.C.
Midcoast Operating	Midcoast Operating, L.P., the operating subsidiary of MEP
MLP	Master Limited Partnership
MMBtu/d	Million British Thermal units per day
MMBbls	Million Barrels of liquids
MMcf/d	Million cubic feet per day
Mid-Continent system	Crude oil pipelines and storage facilities located in the Mid-Continent region of the United States and includes the Cushing tank farm and Ozark pipeline
Moody's	Moody's Investors Service

NEB	National Energy Board, a Canadian federal agency that regulates Canada's energy industry
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
North Dakota system	Liquids petroleum pipeline gathering system and common carrier pipeline in the Upper Midwest United States that serves the Bakken formation within the Williston basin
North Texas system	Natural gas gathering and processing assets located in the Fort Worth basin serving the Barnett Shale area
NSPS	New Source Performance Standards
NTSB	National Transportation Safety Board
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
Offering	MEP initial public offering
OLP	Enbridge Energy, Limited Partnership, also referred to as the Lakehead Partnership
OPA	Oil Pollution Act
PADD	Petroleum Administration for Defense Districts
PADD II	Consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin
PADD III	Consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas
PADD IV	Consists of Colorado, Idaho, Montana, Utah and Wyoming
PADD V	Consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington
Partnership Agreement	Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P., also referred to as our partnership agreement
Partnership	Enbridge Energy Partners, L.P. and its consolidated subsidiaries
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES of 2006	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006
Ppb	Parts per billion
PPI-FG	Producer Price Index for Finished Goods
PSA	Pipeline Safety Act of 1992
ROE	Return on Equity
SAGD	Steam assisted gravity drainage
S&P	Standard & Poor's
SEC	United States Securities and Exchange Commission
SEP II	System Expansion Program II, an expansion program on our Lakehead system
Series AC interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the Alberta Clipper Pipeline
Series EA interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the Eastern Access Projects
Series LH interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the Lakehead System, excluding those designated by the Series AC interests
Series ME interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the U.S. Mainline Expansion projects
SIP	Texas State Implementation Plan
SO2	Sulfur Dioxide
SORA	Submerged Oil Recovery and Assessment workplan
Southern Access	Southern Access Pipeline, a 42-inch pipeline that runs from Superior, Wisconsin to Flanagan, Illinois on our Lakehead system
Suncor	Suncor Energy Inc., an unrelated energy company
Syncrude	Syncrude Canada Ltd., an unrelated energy company

Tariff Agreement	A 1998 offer of settlement filed with the FERC
TRRC	Texas Railroad Commission
TSX	Toronto Stock Exchange
UBTI	Unrelated Business Taxable Income
U.S. GAAP	United States Generally Accepted Accounting Principles
U.S. Mainline Expansion projects	Multiple projects that will expand access to new markets in North America for growing production from western Canada and the Bakken Formation
VOC	Volatile Organic Compound
WCSB	Western Canadian Sedimentary Basin

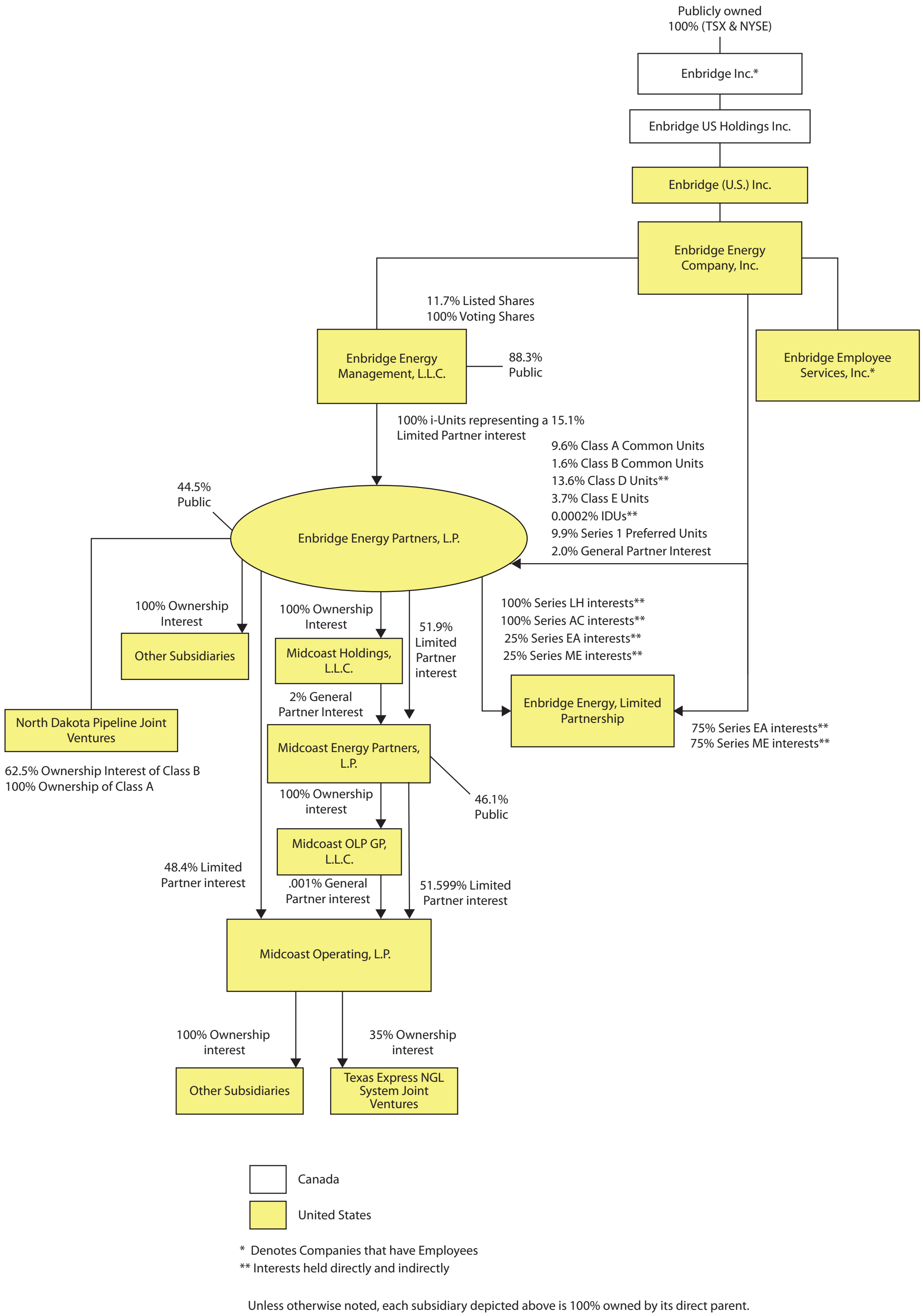
PART I

Item 1. Business

OVERVIEW

We are a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transportation and marketing assets in the United States of America. Our Class A common units are traded on the New York Stock Exchange, or NYSE, under the symbol EEP.

The following chart shows our organization and ownership structure as of December 31, 2015. The ownership percentages referred to below illustrate the relationships between us, Enbridge Energy Management, L.L.C., or Enbridge Management, Enbridge Energy Company, Inc., or our General Partner, and Enbridge Inc., or Enbridge, and its affiliates:



We were formed in 1991 by our General Partner, initially to own and operate the Lakehead system, which is 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, referred to as the Mainline system. A subsidiary of Enbridge owns the Canadian portion of the Mainline system. Enbridge is a leading provider of energy transportation, distribution and related services in North America and internationally. Enbridge is the ultimate parent of our General Partner.

Enbridge Management is a Delaware limited liability company that was formed in May 2002 to manage our business and affairs. Under a delegation of control agreement, our General Partner delegated substantially all of its power and authority to manage our business and affairs to Enbridge Management. Our General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management is the sole owner of i-units.

BUSINESS STRATEGY

Our primary objective is to provide stable, growing and sustainable cash distributions to our unit holders, while maintaining a relatively low-risk investment profile. Our business strategies focus on creating value for our customers, which we believe is the key to creating value for our investors. To accomplish our objective, we focus on the following key strategies:

1. Operational excellence

   We will continue to focus on safety, environmental integrity, innovation and effective stakeholder relations. We strive to operate our existing infrastructure to provide flexibility for our customers and ensure system capacity is reliable and available when required.

2. Expanding our core asset platforms

   We intend to develop energy transportation assets and related facilities that are complementary to our existing systems. This will be achieved primarily through organic growth. Our core businesses provide plentiful opportunities to achieve our primary business objectives. We may also expand our core asset platforms through purchase of assets from Enbridge.

3. Project Execution

   Our Major Projects group is committed to executing and completing projects safely, on time and on budget. These include new builds, organic growth and expansion projects.

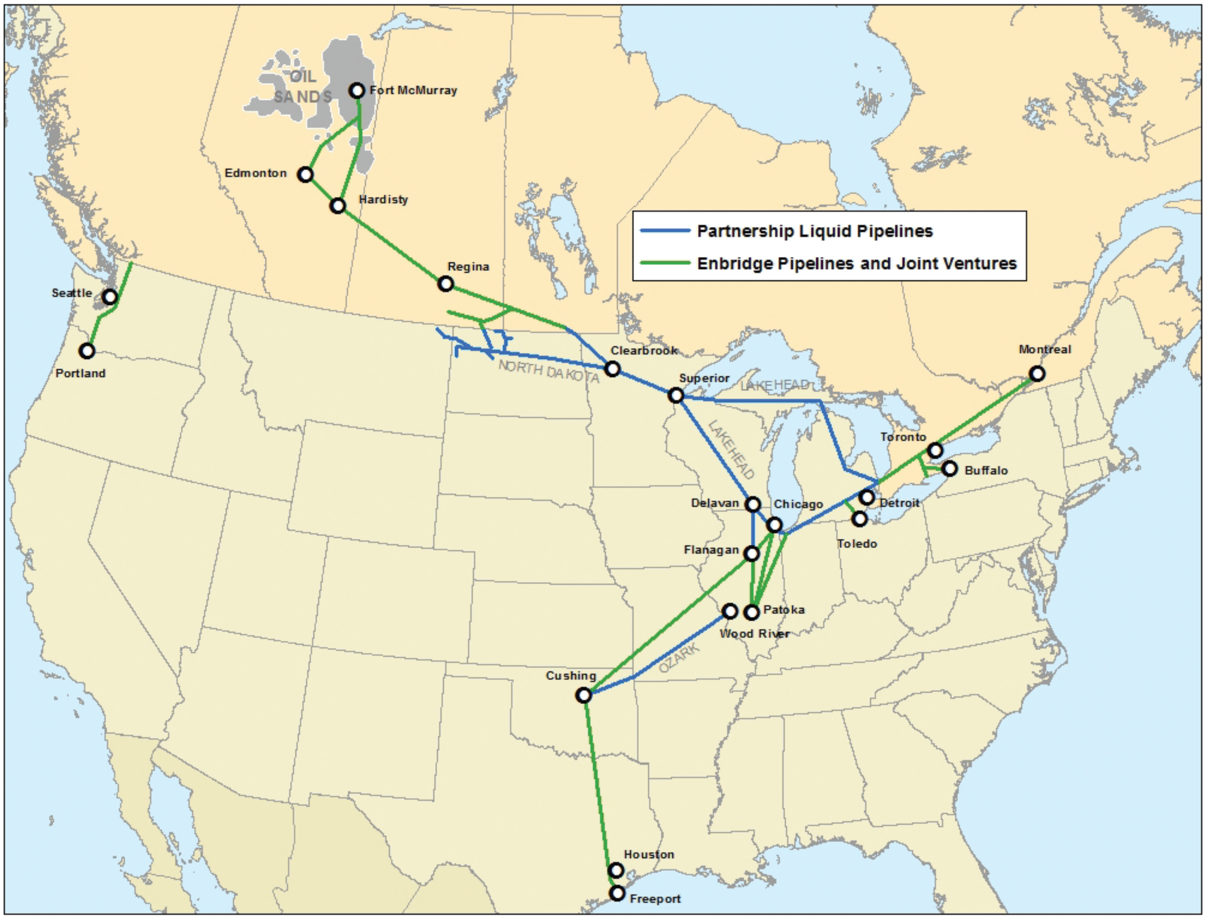
4. Developing new asset platforms

   We plan to develop and acquire new assets to meet customer needs by expanding capacity into new markets with favorable supply and demand fundamentals. This includes the potential of purchasing additional assets from Enbridge.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses while remaining focused on the safe, reliable, effective and efficient operation of our current assets. We are well positioned to pursue opportunities for accretive acquisitions in or near the areas in which we have a competitive advantage. We intend to execute our growth strategy by maintaining a capital structure that balances our outstanding debt and equity in a manner that sustains our investment grade credit rating.

Liquids

The map below presents the locations of our current Liquids systems' assets and projects being constructed. The map also depicts some Liquids Pipelines assets owned by Enbridge and projects being constructed to provide an understanding of how they interconnect with our Liquids systems.



The following discussion provides an overview of North American production that is transported on our pipelines and the projects that we are pursuing to connect the growing supplies of this production to key refinery markets in the United States.

In 2015, we transported production from the Western Canadian Sedimentary Basin, or WCSB, and the North Dakota Bakken formation. Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2015 from the United States Department of Energy's, or DOE, Energy Information Administration, or EIA, Canada supplied approximately 3.1 million barrels per day, or Bpd, of crude oil to the United States, the largest source of United States imports. Over half of the Canadian crude oil moving into the United States was transported on the Mainline system. The Canadian Association of Petroleum Producers, or CAPP, forecasts as of June 2015 that future production from the Alberta oil sands will continue to experience steady growth during the next two decades with an additional 1.7 million Bpd of production by 2030, based on a subset of currently approved applications and announced expansions. We are well positioned to deliver growing volumes of crude oil that are expected from the WCSB to our existing as well as new markets.

North Dakota, Montana and Saskatchewan, Canada continued to experience growth in the development of crude oil, natural gas, and NGLs from the Bakken and Three Forks formations. The latest data released in 2013 by the United States Geological Survey estimates that technically recoverable oil in the Bakken and Three Forks formation in North Dakota has doubled to approximately 7.4 billion barrels.

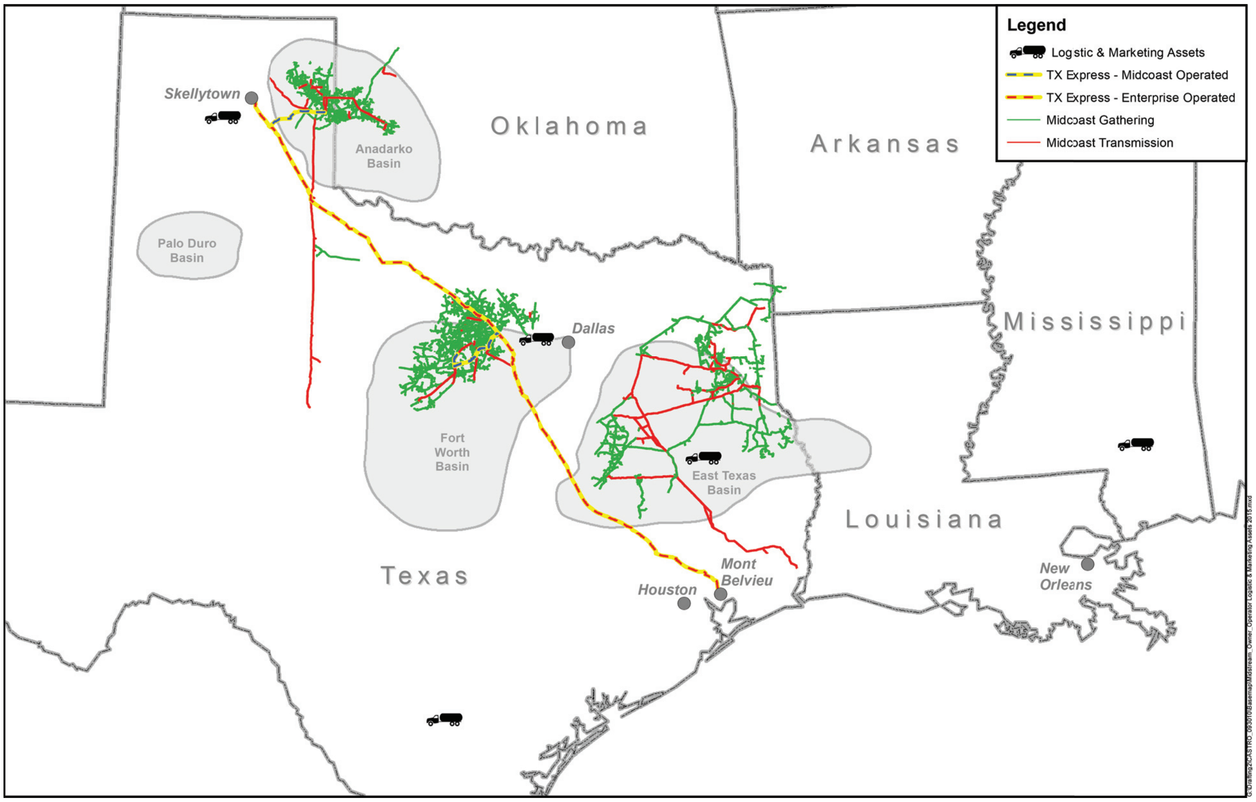
Along with Enbridge, we are actively working with our customers to develop transportation options that will alleviate capacity constraints in addition to providing access to new markets in the United States. Our market strategy is to provide safe, timely, economic, competitive, integrated transportation solutions to connect growing supplies of North American crude oil production to key refinery markets in the United States and Canada. Together, our existing and future plans advance our vision of being the leading energy delivery company in North America. In addition to this vision, we have advanced our Operational Risk Management Program. It includes a state-of-the-art Liquids Pipelines control center and the most extensive maintenance, integrity and inspection program in the history of the North American pipeline industry, with 933 in-line inspections and 13,005 pipeline integrity verification digs completed by Enbridge and us from 2010 through 2015.

We have a multi-billion dollar growth program underway, with projects coming into service through early 2019 in addition to options to increase our economic interest in projects that are jointly funded by us and Enbridge. As part of this growth program, we and Enbridge have invested in a Light Oil Market Access Program to expand access to markets for growing volumes of light oil production. This program responds to significant recent developments with respect to supply of light oil from U.S. north central formations and western Canada, as well as refinery demand for light oil in the U.S. Midwest and eastern Canada. The Light Oil Market Access Program includes several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Project, enhance Enbridge's Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries. Some of these projects include the Eastern Access and Mainline Expansions, as well as the Sandpiper project.

In addition to the Light Oil Market Access Program, we and Enbridge announced the Line 3 Replacement Program. While the Line 3 Replacement Program will not provide an increase in the overall capacity of the mainline system, it supports the safety and operational reliability of the system, enhances flexibility and will allow us and Enbridge to optimize throughput from Western Canada into Superior, Wisconsin. This project, along with the Light Oil Market Access projects, will provide increased market access for producers to refineries in the United States upper-Midwest, Eastern Canada, and the United States Gulf Coast refining centers. For further details regarding our projects, refer to Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*, Results of Operations — By Segment.

Natural Gas

The map below presents the locations of our current Natural Gas systems assets. These assets are owned by Midcoast Energy Partners, L.P., or MEP, and its subsidiaries. MEP is a Delaware limited partnership we formed to serve as our primary vehicle for owning and growing our natural gas and NGL midstream business in the United States. MEP completed its initial public offering, or the Offering, in November of 2013, but we continue to own all of the equity interests in MEP's general partner, a 51.9% limited partner interest in MEP and a 48.4% limited partner interest in MEP's operating subsidiary, Midcoast Operating. This map depicts some assets owned or under development by Enbridge to provide an understanding of how they relate to our Natural Gas systems.



Our natural gas assets are primarily located in Texas and Oklahoma, a region which continues to see limited drilling activity despite commodity pricing challenges. These core basins are known as the East Texas basin, the Fort Worth basin and the Anadarko basin. Our focus has primarily been on developing and expanding the service capability of our existing pipeline systems and acquiring assets with strong growth prospects located in or near the areas we serve or have competitive advantage. We may also target future growth in areas where we can deploy our successful operating strategy to expand our portfolio into other natural gas production regions. Our Natural Gas business also includes trucking, rail and liquids marketing operations that we use to enhance the value of the NGLs produced at our processing plants.

The operations and commercial activities of our gathering and processing assets and intrastate pipelines are integrated to provide better service to our customers. From an operations perspective, our key strategies are to provide safe and reliable service at reasonable costs to our customers and capitalize on opportunities for attracting new customers. From a commercial perspective, our focus is to provide our customers with a greater value for their commodity. We intend to achieve this latter objective by increasing customer access to preferred natural gas markets and NGLs. The aim is to be able to move significant quantities of natural gas and NGLs from our Anadarko, North Texas and East Texas systems to the major market hubs in Texas and Louisiana. From these market hubs, natural gas can be used in the local Texas markets or transported to consumers in the Midwest, Northeast and Southeast United States. The primary market hub for NGLs is the fractionation center in Mont Belvieu, Texas, with its access to refineries, petro-chemical plants, export terminals and outbound pipelines.

The long term prospects in our core areas remain favorable, primarily as a result of technological advancements that have enhanced production of natural gas and NGLs from tight sand and shale formations. The reserves and resource potential in all three of our operating basins is substantial. The current price environment has forced producers to be more selective in their drilling efforts, with many producers high-grading well selection to the core portion of production areas. When natural gas prices recover to the level that will incentivize producers to drill their lean gas prospects, our core assets are well positioned to gather, treat and transport this gas to market. Our goal is to offer our customers the ability to gather, process, and transport their liquids to major markets.

BUSINESS SEGMENTS

We conduct our business through two business segments: Liquids and Natural Gas. 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 Part II, Item 8. *Financial Statements and Supplementary Data*, Note 16. *Segment Information*.

Liquids Segment

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. The following table provides selected information regarding our Liquids systems:

	Pipeline Length (miles)	Storage Tanks	Storage Capacity (million barrels)[1]	Pump Stations
Lakehead	5,022	77	18.1	73
Mid-Continent	433	100	23.6	10
North Dakota	683	31	1.8	23
Total	6,138	208	43.5	106

(1) Represents nominal shell capacity

Lakehead system

Our Lakehead system, together with the Enbridge system in Canada, form the Mainline system, which has been in operation for over 60 years and forms the longest liquid petroleum pipeline system in the world. The Mainline system operates in a segregated, or batch, mode allowing the transportation of 35 crude oil commodities typically classified as light, medium, or heavy crude oil, condensate, and NGLs. The Mainline system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. The Lakehead system is the U.S. portion of Enbridge Inc.'s Mainline system. It is an interstate common carrier pipeline system regulated by the FERC, and is the primary transporter of crude oil and liquid petroleum from Western Canada to the United States.

Over the past six years, we have completed the largest pipeline expansion program in our history in order to accommodate the growing upstream supply that will feed our completed downstream market access projects. Our customers have long development timelines and need assurance that adequate pipeline infrastructure will be in place in time to transport the additional production resulting from completion of their projects. The projects included in our Eastern Access, Light Oil Market Access, U.S. Gulf Coast access, and associated Mainline/Lakehead expansion initiatives will provide the needed incremental market access for both our producer and refiner customers located in our primary target markets.

Our Lakehead system is strategically interconnected to multiple refining centers and transportation hubs located within Petroleum Administration for Defense Districts, or PADD, II such as: Chicago, Illinois; Patoka, Illinois; and Cushing, Oklahoma. In addition, we are also strategically connected to the largest U.S. refining center in the U.S. Gulf Coast through other pipelines owned by Enbridge and its affiliates. WCSB production in excess of Western Canadian demand moves on existing pipelines into primarily PADD II, with secondary markets including: the U.S. Gulf Coast (PADD III); the Rocky Mountain states (PADD IV); the Anacortes area of Washington state (PADD V); and to Eastern Canada (Ontario).The Lakehead system mainly serves the PADD II market directly and the PADD III market indirectly. Bakken production in excess of local demand primarily moves on existing pipelines into PADD II or is transported by rail to coastal Canadian and U.S. refining markets. The U.S. Gulf Coast continues to be an attractive market for WCSB producers due to the market's large refining capacity designed to process heavy crude oil. The forecasted long-term incremental growth of Canadian oil sands and Bakken production provides stability for existing pipeline throughputs to historical markets as well as creating new growth opportunities available to both us and our competitors.

Customers. Our Lakehead system operates under month-to-month transportation arrangements with our shippers. During 2015, approximately 38 shippers tendered crude oil and liquid petroleum for delivery through our Lakehead system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Lakehead system. Our customers include integrated oil companies, major independent oil producers, refiners and marketers.

Supply and Demand. Our Lakehead system is part of the longest crude oil pipeline in the world and is a critical component of the North American crude oil supply pipeline network. Lakehead is well positioned as the primary transporter of Western Canadian crude oil and continues to benefit from past and anticipated future crude oil production growth from the Alberta Oil Sands, as well as recent development in tight oil production in North Dakota. Aside from the receipt locations on the Mainline system within Canada, our Lakehead system receives injections from locations within the United States. Clearbrook, Minnesota is the receipt location for U.S. Bakken production, and other U.S. sources are received at Lewiston, Michigan and Mokena, Illinois.

Crude oil originating from the WCSB comprises the majority of Lakehead system deliveries. According to the Energy Information Administration, or EIA, Canada is currently ranked third in the world for total proved reserves, just behind Saudi Arabia and Venezuela, respectively. The NEB estimates that 98% of Canada's total proved reserves are attributed to Alberta's oil sands bitumen, with the remainder being conventional oil sources. The Alberta Energy Regulator, or AER, estimates 168.1 billion total barrels, or approximately 166.3 billion and 1.8 billion barrels of established proved bitumen and conventional reserves, respectively, remain for the region as of 2015. The NEB estimates that total production from the WCSB averaged approximately 3.6 million Bpd in 2015 and 3.5 million in 2014. Furthermore, these production levels are expected to grow in the future, as previously discussed.

The growth forecast in the oil sands will be primarily driven by steam assisted gravity drainage, or SAGD, projects in the long-term. Mining projects are the main contributor to near-term growth, with other development projects on hold until prices recover and well economics improve. Based on projects currently under construction in Western Canada, the incremental productive capacity that would have access to our systems is reported to increase over the next three years by approximately 450,000 Bpd.

North Dakota's Bakken resource play has grown since 2010, and has become a major component of United States domestic supply. Lakehead throughput volumes are primarily supplied by crude oil produced in the Canadian oil sands and Bakken resource plays. Crude oil supply from the Bakken region has outperformed historical expectations as production now exceeds 1.2 million Bpd, with projections of stabilizing at that level or growing at a low rate due to low oil prices. Forecasts of Western Canadian crude oil supply are periodically completed by Enbridge, CAPP and the NEB, among others. Western Canada oil sands production is expected to grow by 1.7 million Bpd to over 3.9 million Bpd by 2030. This compares with an expected decrease of 100,000 Bpd from conventional production sources over the same time frame. CAPP revised its oil sands production forecast downward by 900,000 Bpd in 2015 from 4.8 million Bpd to 3.9 million Bpd due to the low oil price environment and constraints arising from oil sands cost competitiveness and delays in project schedules. Despite the revisions, the production growth forecasted out of our primary supply markets requires additional pipeline capacity.

PADD II is the primary demand market for our Lakehead system. Deliveries on our Lakehead system are negatively affected by periodic maintenance, other competitive transportation alternatives, or refinery turnarounds and other shutdowns at producing plants that supply crude oil. Based on growth in Western Canadian and Bakken crude oil supply and Lakehead operational performance improvements, deliveries on our Lakehead system are expected to grow beyond the 2.3 million Bpd of actual deliveries experienced during 2015.

The latest data available from the EIA shows that total PADD II demand was 3.5 million Bpd. PADD II produced 1.9 million Bpd and imported 2.1 million Bpd from Canada and other regions located in the United States, with exports comprising the remaining difference between PADD II supply and demand. Imports from Canada comprised 98% of total PADD II crude oil imports, with approximately 63% or 1.3 million Bpd transported on our Lakehead system. The remaining barrels were imported via competitor pipelines from Alberta and offshore sources via the U.S. Gulf Coast or regional transfers from PADD III or PADD IV.

Lakehead system deliveries for 2015 were approximately 202,000 Bpd higher than delivery volumes for 2014. Total deliveries from our Lakehead system averaged 2.3 million Bpd in 2015, meeting approximately 76% of the refinery capacity in the greater Chicago area; 76% of the Minnesota refinery capacity; and 84% of Ontario refinery capacity. Refinery configurations and crude oil requirements within PADD II continue to create an attractive market for Western Canadian and Bakken supply. However, Crude oil demand in PADD II averaged 3.5 million Bpd, an increase of only 23,000 Bpd from 2014. Moreover, overall refining utilization remained relatively flat in 2015 compared to 2014 for PADD II as utilization fell approximately 0.3%.

Competition. WCSB crude oil competes with local and imported crude oil. Of all the pipeline systems that transport crude oil out of Canada, the Mainline system transported approximately half of all Canadian crude oil imports into the United States in 2015.

Our Eastern Access, Light Oil Market Access, U.S. Gulf Coast Access, and associated Mainline expansion projects will improve the flexibility of our system and are designed to increase Lakehead throughput by reaching new markets. Given the expected increase in crude oil production from the Alberta Oil Sands over the next 10 years, alternative transportation proposals have been presented to crude oil producers. Competitors' proposals to WCSB and Bakken shippers include expanding, twinning, extending and building new pipeline assets. These proposals and projects are in various stages of regulatory approval.

Transportation of crude oil by rail has also emerged as a competitor primarily due to the lack of pipeline capacity for the WCSB and Bakken regions. As a result, a significant amount of rail loading capacity has been constructed and is proposed in both markets. Rail transportation becomes less competitive, however, as crude oil price differentials narrow between key markets due to high transportation costs relative to cost of transportation by pipeline.

These competing alternatives for delivering Western Canadian crude oil into the United States and other markets could erode shipper support for further expansion of our Lakehead system. Accordingly, competition could also impact throughput on and utilization of the Mainline system. The Mainline system, however, offers significant cost savings and flexibility to shippers.

Deliveries for our Lakehead system over the past five years were as follows:

	2015	2014	2013	2012	2011
			(thousands of Bpd)		
United States					
Light crude oil	500	496	473	521	473
Medium and heavy crude oil	1,364	1,167	948	879	850
NGL	5	6	6	5	4
Total United States	1,869	1,669	1,427	1,405	1,327
Ontario					
Light crude oil	294	298	247	228	220
Medium and heavy crude oil	77	72	76	85	84
NGL	75	74	66	72	69
Total Ontario	446	444	389	385	373
Total Deliveries	2,315	2,113	1,816	1,790	1,700
Barrel miles (billions per year)	640	582	487	480	450

Mid-Continent system

Our Mid-Continent system, which we have owned since 2004, is located within PADD II and is comprised of our Ozark pipeline and storage terminals at Cushing, Oklahoma and Flanagan, Illinois. Our Ozark pipeline transports crude oil from Cushing, Oklahoma to Wood River, Illinois, where it delivers to the WRB refinery, a joint venture between Cenovus Energy and Phillips 66 located at Wood River, and interconnects with the Woodpat Pipeline and the Wood River Pipeline, each owned by unrelated parties.

The storage terminals consist of 100 individual storage tanks ranging in size from 78,000 to 575,000 barrels. Of the approximately 23.6 million barrels of storage shell capacity on our Mid-Continent system, the Cushing terminal accounts for approximately 20.1 million barrels. A portion of the storage facilities are used for operational purposes, while we contract the remainder of the facilities with various crude oil market participants for their term storage requirements. Contract fees include fixed monthly capacity fees as well as utilization fees, which we charge for injecting crude oil into and withdrawing crude oil from the storage facilities.

Customers. Our Mid-Continent system operates under month-to-month transportation arrangements as well as long-term and short-term storage arrangements with shippers. During 2015, approximately 47 shippers tendered crude oil for service on our Mid-Continent system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Average deliveries on the Ozark pipeline system were 212,000 Bpd for 2015 up from 200,000 Bpd for 2014.

Supply and Demand. Our Mid-Continent system is positioned to capitalize on increasing demand for both domestic and imported crude oil, specifically Canadian imports into the United States. Our Ozark pipeline system currently serves an exclusive corridor between Cushing, Oklahoma and Wood River, Illinois, delivering crude commodities with low viscosities and sulfur content at more competitive prices than similar commodities accessible from other sources. In addition, the Cushing terminal remains in high demand as a result of superior connectivity. Despite low commodity prices, we anticipate an increase in volumes on the Mid-Continent system as a result of Enbridge's Flanagan South Pipeline and other newly constructed third-party pipelines. In 2015, PADD II imported 2.1 million Bpd from outside of the PADD II region, the majority of which were imported from Canada primarily on our Lakehead system. The remaining barrels of crude oil were imported from PADDs III and IV as well as offshore sources. We expect the demand for local supply to increase and the demand for Canadian crude to stay strong, thus displacing the necessity for other foreign sources.

Competition. As previously mentioned, our Ozark pipeline system currently serves an exclusive corridor between Cushing, Oklahoma and Wood River, Illinois. However, refineries connected to Wood River, Illinois have crude oil supply options available from Canada via our Lakehead system as well as third-party pipelines. These same refineries also have access to the United States Gulf Coast and foreign crude oil supply through a third-party pipeline system, which is an undivided joint interest pipeline that is owned by unrelated parties. In addition, refineries located east of Patoka, Illinois with access to crude oil through our Ozark system also have access to west Texas supply from the Permian Basin through the West Texas Gulf/Mid-Valley Pipeline systems owned by unrelated parties. Our Ozark pipeline system faces competition from a competitor's pipeline from Hardisty, Alberta to Patoka, Illinois. Furthermore, anticipated completion of an additional third-party pipeline in late 2016 will allow the delivery of commodities similar to those currently delivered by our Ozark pipeline, potentially impacting our current competitive advantages. To date, our Ozark system has remained full. If a negative impact does occur to the volumes on our Ozark system, we will consider alternative uses for our Ozark system.

Our storage terminals rely on demand for storage service from numerous oil market participants. Producers, refiners, marketers and traders value our storage capacity in Cushing, Oklahoma for a number of different reasons, including batch scheduling, stream quality control, inventory management, and speculative trading opportunities. Demand for storage capacity at Cushing, Oklahoma has remained high as customers continue to value the flexibility and optionality available with this service as well as the superior connectivity that our terminal offers. Competitors to our storage facilities at Cushing, Oklahoma include large integrated oil companies, private entities and other midstream energy partnerships. Many of these competitors have the capability to expand in the future and better compete on quality of service, reliability, increased connectivity and price.

North Dakota system

Our North Dakota system is a crude oil gathering and interstate pipeline transportation system servicing the Williston Basin in North Dakota and Montana, which includes the highly publicized Bakken and Three Forks formations. The gathering pipelines that comprise our North Dakota system collect crude oil from nearly 100 different receipt facilities located throughout western North Dakota and eastern Montana, including nearly 20 third party gathering pipeline connections, and deliver a fungible common stream to a variety of interconnecting pipeline and rail export facilities.

Traditionally, the majority of our pipeline deliveries have been made into interconnecting pipelines at Clearbrook, Minnesota where two other pipelines originate: (1) a third-party pipeline serving St. Paul, Minnesota refinery markets; and (2) our Lakehead system providing further pipeline transportation on the Enbridge system into the Great Lakes, eastern Canada and U.S. Midwest refinery markets that include Cushing, Oklahoma, Patoka, Illinois, and other pipelines delivering crude oil to the U.S. Gulf Coast. We have significantly increased the pipeline and rail export capacity of our North Dakota system through a series of projects in recent years while continuing to serve the system's traditional markets in order to provide an array of market options and services.

Customers. Customers of our North Dakota system include refiners of crude oil, producers of crude oil and purchasers of crude oil at the wellhead, such as marketers, that require crude oil gathering and transportation services. Producers range in size from small independent owner/operators to large integrated oil companies. During 2015, approximately 140 shippers tendered crude oil for service on our North Dakota system.

Supply and Demand. Similar to our Lakehead system, our North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States and the ability of crude oil producers to maintain their crude oil production and exploration activities. The state of North Dakota reported production levels of 1.2 million Bpd as of November 2015 with projections of stabilizing at that level or growing at a low rate due to low oil prices.

Competition. Due to the growth in production from these formations over the last several years, competition has increased substantially. Traditional competitors of our North Dakota system include refiners, integrated oil companies, interstate and intrastate pipelines or their affiliates and other crude oil gatherers. Many crude oil producers in the oil fields served by our North Dakota system have alternative gathering facilities available to them or have the ability to build their own assets, including their own rail loading facilities.

Currently, the primary competition to our North Dakota system is rail. Initially considered a niche or alternative form of transportation, rail currently represents more than 40% of the total Bakken crude exported from North Dakota. Rail provides some advantages to pipeline transportation, but future Enbridge pipeline expansions and enhanced market access to Eastern Canadian markets and eastern PADD II are reducing these advantages when it comes to shipping alternatives. As pipeline expansion projects create more export capacity from the Bakken and other pipeline projects provide increased access to more refinery markets across the United States, we expect North Dakota customers will shift volumes back to pipelines.

There are a number of third-party pipelines with proposed expansions to increase capacity and take advantage of the Bakken and Three Forks volume growth. Many of these third party pipeline projects include pipeline connections into our North Dakota system as part of their project scope.

Natural Gas Segment

Our natural gas business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities, condensate stabilizers and an NGL fractionation facility, as well as trucking, rail and liquids marketing operations. 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, using the Texas Express NGL system, we gather NGLs from certain of our facilities for delivery on the Texas Express NGL mainline to Mont Belvieu, Texas.

The following table provides selected information regarding our natural gas and NGL systems in our natural gas business:

	Natural gas gathering and transportation pipelines (length in miles)	NGL pipelines (length in miles)[4]	Number of active natural gas processing plants	Number of standby natural gas processing plants	Number of active natural gas treating plants	Number of standby natural gas treating plants
Anadarko system	3,200	61	5	7	—	1
East Texas system[1]	4,000	176	6	1	5	4
North Texas system	3,700	29	6	—	—	—
Total	10,900	266	17	8	5	5
Texas Express NGL system[2]	—	709[3]	—	—	—	—

(1) In addition, approximately one hydrocarbon dewpoint control facility, or HCDP plant, and one fractionation facility are located in the East Texas basin.

(2) We have a 35% interest in the Texas Express NGL system, which commenced startup operations during the fourth quarter of 2013.

(3) Consists of approximately 593-mile NGL intrastate transportation mainline and a related NGL gathering system that consists of approximately 116 miles of gathering lines.

(4) In the third quarter of 2015, MEP sold its non-core Louisiana propylene pipeline.

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. Recent decreases in NGL and condensate prices have resulted in decreased activity in the region. The Anadarko basin wells generally have long lives with predictable flow rates. Producers generally pursue wells with higher condensate and oil production relative to historical activity that was focused on natural gas and NGL prospects.

With recent commodity prices in decline resulting in reduced production, we have idled approximately seven of our less efficient processing plants and consolidated volumes to our more efficient plants. These plants are available for restart when production increases.

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. 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 among others, the Woodbine, Travis Peak, James Lime, Rodessa, and Pettite. The East Texas wells generally have long lives with predictable flow rates.

The Eaglebine is an emerging oil play in East Texas that spans over five counties and is comprised of multiple formations, including but not limited to, the Woodbine, Buda, Glenrose and Eagle Ford formations. We have a series of construction projects and an acquisition in this play. In February 2015, we acquired from NGR its midstream operations, which consist of a natural gas gathering system, in Leon, Madison and Grimes counties, Texas. We have completed construction of the Ghost Chili pipeline project, which consists of lateral and associated facilities that create gathering capacity of over 50 MMcf/d for rich natural gas to be delivered from Eaglebine production areas to our complex of cryogenic processing facilities in East Texas. The initial facilities were placed in service in October 2015. We also expect to construct the Ghost Chili Extension Lateral to fully utilize this gathering capacity with the rest of our processing assets when additional development in the basin supports it. Given the proximity of our existing East Texas assets, this expansion into Eaglebine will allow us to offer gathering and processing services while leveraging assets on our existing footprint.

In May 2015, we placed into service a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville Processing Plant. This plant serves existing and prospective customers pursuing production in the Cotton Valley formation, which is comprised of approximately ten counties in East Texas. Production from the Cotton Valley formation typically contains two to three gallons of NGLs per Mcf of natural gas. Our Beckville processing plant is 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 within this geographical area in which our East Texas system operates. Related NGL takeaway infrastructure connecting the Beckville plant to third-party NGL transportation systems was also constructed. In 2015, our processing plants in East Texas were near or at full capacity.

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. 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 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. As producers have shifted from drilling dry natural gas to rich gas from crude oil production, we have seen our natural gas volumes decline.

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. All of our owned condensate and NGLs produced at our North Texas system processing plants is sold to our trucking and marketing business.

Texas Express NGL System

The Texas Express NGL system consists of an NGL gathering system and an NGL intrastate mainline transportation pipeline that originates in Skellytown, Texas and extends to NGL fractionation and storage facilities located in Mont Belvieu, Texas. The Texas Express NGL system commenced startup operations during the fourth quarter of 2013. Volumes from the Rockies, Permian basin and Mid-Continent regions are 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 can access the system through the Front Range Pipeline which is owned by Enterprise Products Partners, DCP Midstream and Anadarko Petroleum Corporation.

Customers. Our natural gas business serves customers predominantly in the Gulf Coast region of the United States and include 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 associated natural gas crude oil development and the drilling rate for new wells. The level of impurities in the natural gas gathered also affects treating services. All of our natural gas 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. Demand for these services depends upon overall economic conditions, drilling activity and the prices of natural gas, NGLs, and condensates. Commodity prices for natural gas, NGLs, and condensates have declined in the second half of 2014 and in 2015. As a result, there has been reduction in drilling activity by producers and reduced volumes on the systems we operate. Our existing systems are located in basins that have the opportunity to grow in an improved pricing environment.

Competition. Competition for our natural gas 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's 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. 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.

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. 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.

Trucking and Marketing Operations

The primary role of our trucking and marketing business is to provide marketing services of natural gas, NGLs and condensate. We purchase and receive natural gas, NGLs and other products from pipeline systems and processing plants, including those owned by us, and sell and deliver them to wholesale customers, distributors, refiners, fractionators, chemical facilities, various third parties and end users. A majority of the natural gas and NGLs we purchase are produced in Texas markets where we have expanded interstate deliverability alternatives over the past several years. We can use our connectivity to interstate pipelines to improve value for the producers by delivering natural gas into premium markets and NGLs to primary markets where we sell them to major customers. Additionally, our trucking and marketing business derives operating income from providing trucking services for our customers from the wellhead to markets.

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

- Approximately 200 transport trucks, 370 trailers and 200 railcars for transporting NGLs; and
- Our TexPan liquids railcar facility near Pampa, Texas.
- our Petal truck & rail facility near Hattiesburg, Mississippi.

We also enter into agreements with various third parties to obtain NGL supply, transportation, gas balancing, fractionation and storage capacity in support of the trucking and marketing services provided. These agreements supply us with the following:

- Up to approximately 79,000 Bpd through 2022 of firm NGL fractionation capacity;
- Up to approximately 30,000 Bpd in 2016 to 120,000 Bpd in 2022 of firm NGL transportation capacity on the Texas Express NGL system;
- Up to approximately 39,000 Bpd through 2022 of additional firm NGL transportation capacity on third-party pipelines;
- Up to approximately 56,555 Bpd through 2017 of NGL capacity via exchange agreements with various counterparties; and
- Approximately 5.0 million barrels of liquids, or MMBbls, of NGL storage capacity.

Customers. Most of our customers are natural gas aggregators, wholesale customers, refiners and petrochemical producers, fractionators, propane distributors and industrial customers, various third parties and end users.

Supply and Demand. Supply for our trucking 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 a number of factors such as physical domestic and international industrial requirements.

Since major market hubs for NGLs and related products are located in the Mid-Continent and Gulf Coast regions of the United States and our trucking and marketing assets are geographically located within Texas, Louisiana, Oklahoma and Mississippi, the majority of activities are conducted within those states. Our interconnected gathering and transportation systems and our fleet of trucks, trailers and railcars mitigate 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 trucking and marketing business is our natural gas and NGL purchase and resale activities. Through our natural gas and NGL purchase and resale services, we can efficiently manage the transportation and delivery of natural gas from our gathering, processing and transportation systems and deliver them to on-system industrial plant customers, and NGLs to marketing companies at various market hubs. We typically price our sales based on multiple published daily or monthly price indices. 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.

We also use third-party storage facilities and pipelines for the right to store NGLs for various periods of time to mitigate risk associated with sales and purchase contracts. 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 trucking and marketing operations have numerous competitors, including large 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.

Seasonality

The drilling activities of producers within our areas of operations generally do not vary materially by season but may be affected by adverse weather. 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 customers is typically driven by weather-related factors.

REGULATION

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

The FERC regulates the interstate pipeline transportation of crude oil, petroleum products, and other liquids such as NGLs, collectively called ''petroleum pipelines'' or ''liquids pipelines.'' Our Lakehead, North Dakota, Bakken and Ozark systems are our primary interstate common carrier liquids pipelines subject to regulation by the FERC under the Interstate Commerce Act, or ICA, the Energy Policy Act of 1992, or EP Act, and rules and orders promulgated thereunder. As common carriers in interstate commerce, these pipelines provide service to any shipper who makes a reasonable request for transportation services, provided that the shipper satisfies the conditions and specifications contained in the applicable tariff. The ICA requires us to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier pipelines, as well as the rules and regulations governing these services.

The ICA gives the FERC the authority to regulate the rates we can charge for service on interstate common carrier pipelines. The ICA requires, among other things, that such rates be ''just and reasonable'' and that they not be unduly discriminatory or unduly preferential to certain shippers. The ICA permits interested parties to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate the rates to determine if they are just and reasonable. If the FERC finds the new or changed rate unlawful, it is authorized to require the carrier to refund, with interest, the amount of any revenues in excess of the amount that would have been collected during the term of the investigation at the rate properly determined to be lawful. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

In October 1992, Congress passed the EP Act, which deemed petroleum pipeline rates that were in effect for the 365-day period ending on the date of enactment, or that were in effect on the 365^{th} day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period, to be just and reasonable under the ICA (i.e., ''grandfathered''). The EP Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party must show: (1) that it was contractually barred from challenging the rates during the relevant 365-day period; (2) that there has been a substantial change after the date of enactment of the EP Act in the economic circumstances of the pipeline or in the nature of the services that were the basis for the rate, or (3) that the rate is unduly discriminatory or unduly preferential.

The FERC determined our Lakehead system rates are not covered by the grandfathering provisions of the EP Act because they were subject to challenge prior to the effective date of the statute. The rates for our North Dakota and Ozark systems in effect at the time of the EP Act should be found to be subject to the grandfathering provisions of the EP Act because those rates were not suspended or subject to protest or complaint during the 365-day period established by the EP Act.

The EP Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561 which adopted an indexing rate methodology for petroleum pipelines. Under these regulations, which became effective January 1, 1995, petroleum pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels may be protested, but such protests generally must show that the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling, although a pipeline is not required to reduce its rate below the level grandfathered under the EP Act. Under Order No. 561, a pipeline must as a general rule utilize the indexing methodology to change its rates. The FERC, however, uses cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach in certain specified circumstances.

In 2015, the tariff rate for our Ozark system was reset on a cost-of-service basis and is subject to the FERC indexing rules. The tariff rates for our Lakehead, North Dakota and Bakken systems are set using a combination of the FERC indexing rules (which apply to the base rates on those systems), FERC-approved surcharges for particular projects that were approved under the FERC's settlement rules and, in the case of the North Dakota and Bakken systems, contractual agreements.

The inflation index applied to those rates subject to the FERC indexing rules is determined by a formula that is established by FERC and is subject to review every five years. On December 16, 2010, the FERC set the index for the period from July 2011 through June 2016 at the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65 percentage points. Based on this formula, the index resulted in an increase of approximately 4.6%, 3.9%, and 4.6% for 2013, 2014 and 2015, respectively. On December 18, 2015, the FERC set the index for the period from July 2016 through June 2021 at PPI-FG plus 1.23 percentage points.

FERC Allowance for Income Taxes in Interstate Common Carrier Pipeline Rates

Under current FERC policy, pipelines regulated by FERC that are owned by entities organized as Master Limited Partnerships, or MLPs, may include an income tax allowance in their cost-of-service rates to the extent the income generated from regulated activities was subject to an actual or potential income tax liability. Pursuant to this policy, a FERC-regulated pipeline that is a tax pass-through entity seeking such an income tax allowance must establish that its owners, partners or members have an actual or potential income tax obligation on the company's income from regulated activities. Whether a particular pipeline's owners have an actual or potential income tax liability is reviewed by the FERC on a case-by-case basis. To the extent any of our FERC-regulated oil pipeline systems were to file cost-of-service rates, their entitlement to an income tax allowance would be assessed under the FERC policy statement and the facts existing at the relevant time.

FERC Return on Equity Policy for Oil Pipelines

The FERC ROE for oil pipelines is determined using a "two-step" discounted cash flow methodology. This methodology accounts for a long-term growth estimate in addition to a short-term growth rate estimate. For purposes of calculating the long-term growth rate, the FERC has traditionally used projected Gross Domestic Product, or GDP, growth as a proxy for the long-term growth rate. The current FERC policy for calculating ROE was set out in the FERC's Policy Statement regarding Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity. According to the Policy Statement, MLPs are included in the ROE proxy group for oil pipelines, and there is no ceiling on the level of distributions included in the FERC's discounted cash flow methodology. The Policy Statement further indicates that the Institutional Brokers' Estimate System, or IBES, forecasts should remain the basis for the short-term growth forecast used in the discounted cash flow calculation and the respective two-thirds and one-third weightings of the short and long-term growth factors should be used. The Policy Statement also indicates that the GDP forecast used for the long-term growth rate should be reduced by 50% for all MLPs included in the proxy group. The actual ROEs to be calculated under the Policy Statement are dependent on the companies included in the proxy group and the specific conditions existing at the time the ROE is calculated in each case.

Accounting for Pipeline Assessment Costs

The FERC's policies describe how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the United States Department of Transportation, or DOT, and the Pipeline and Hazardous Materials Safety Administration, or PHMSA. FERC-regulated companies are generally required to recognize costs incurred for performing pipeline assessments that are part of a pipeline integrity management program as a maintenance expense in the period in which the costs are incurred. Costs for items such as rehabilitation projects designed to extend the useful life of the system can continue to be capitalized to the extent permitted under the existing rules. Consistent with the FERC's policies, we expense all internal inspection costs for all our pipeline systems, whether or not they are subject to the FERC's regulation. Refer to Note 2. *Summary of Significant Accounting Policies* included in our consolidated financial statements of this annual report on Form 10-K for additional discussion.

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. Pursuant to authority granted to it by the Texas Natural Resources Code, the TRRC has adopted by rule an Informal Complaint Process that applies to rate issues associated with gathering or transmission systems, thus subjecting gathering and intrastate pipeline activities of Enbridge to the jurisdiction of the TRRC.

In Oklahoma, intrastate natural gas pipelines and gathering systems are subject to regulation by the Oklahoma, Corporation Commission, or OCC. Specifically, the OCC is vested with the authority to prescribe and enforce maximum 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 and transmission companies and customers will be mediated by the OCC prior to any hearing on the dispute, upon request. An entity operating an intrastate natural gas pipeline or gathering system in Oklahoma is subject to the jurisdiction of the OCC, and failure to comply with an OCC order regarding rate requirements could result in contempt proceedings instituted before the OCC 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 of 1978, or NGPA. 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 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 of 1938, 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 that is processed or that can be sold into the market without being processed, such gatherers, in their capacity as buyers and sellers of natural gas, are subject to certain reporting requirements resulting from the FERC Order 704 series.

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, state regulators have not historically taken an active role in setting or reviewing rates for gathering facilities absent a shipper protest. 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 the Texas Express NGL system are common carriers subject to 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 NGLs, collectively called ''petroleum pipelines.'' The FERC regulates these operations pursuant to the Interstate Commerce Act, or ICA, and the Energy Policy Act of 1992, or EP Act 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.

The EP Act of 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 levels on Texas Express NGL system were subject to formal review or challenge before the FERC, the Texas Express NGL system would be required to produce a traditional cost of service review justifying its revenues or demonstrate it lacks significant market power.

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 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.

Sales of Natural Gas, Crude Oil, Condensate and Natural Gas Liquids

The price at which we sell natural gas currently is not subject to federal or state regulation except for certain systems in Texas. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and to facilitate price transparency in markets for the wholesale sale of physical natural gas.

Our sales of crude oil, condensate and NGLs currently are not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the ICA. Regulations implemented by the FERC could increase the cost of transportation service on certain petroleum products pipelines, however, we do not believe that these regulations will affect us any differently than other marketers of these products transporting on ICA-regulated pipelines.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to reduce barriers to foreign trade and stimulate the flow of goods and services between the United States and Canada, which includes the passage of oil and natural gas through the pipelines of one country across the territory of the other. Individual international border crossing points require United States government permits that may be terminated or amended at the discretion of the United States Government. These permits provide that pipelines may be inspected by or subject to orders issued by federal and, on occasion, state government agencies.

Tariffs and Transportation Rate Cases

Lakehead system

Under the published rate tariff as of December 31, 2015 for transportation on the Lakehead system, the rates for transportation of light, medium and heavy crude oil from the Canada-United States international border near Neche, North Dakota and from Clearbrook, Minnesota to principal delivery points are set forth below:

	Published Transportation Rate Per Barrel[(1)]		
	Light	Medium	Heavy
From the international border near Neche, North Dakota:			
To Clearbrook, Minnesota	$0.4424	$0.4683	$0.5141
To Superior, Wisconsin	$0.9244	$0.9869	$1.0962
To Chicago, Illinois area	$2.0204	$2.1725	$2.4394
To Marysville, Michigan area	$2.4326	$2.6177	$2.9425
To Buffalo, New York area	$2.4925	$2.6826	$3.0151
Clearbrook, Minnesota to Chicago	$1.7944	$1.9206	$2.1418

(1) Pursuant to FERC Tariff No. 43.19.0 as filed with the FERC and with an effective date of November 1, 2015 (converted from $/cubic meters of liquid, or m3, to $/Barrel of liquids, or Bbl).

The transportation rates as of December 31, 2015 for medium and heavy crude oil are higher than the transportation rates for light crude oil set forth in this table to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. The Lakehead system periodically adjusts transportation rates as allowed under the FERC's index methodology and the tariff agreements described below.

Base Rates

The base portion of the transportation rates for our Lakehead system are subject to an annual adjustment, which cannot exceed established ceiling rates as approved by the FERC and are determined in compliance with the FERC approved index methodology.

Facilities Surcharge Mechanism

In June 2004, the FERC approved an Offer of Settlement in Docket No. OR04-2-000 between Lakehead and CAPP, which implemented a Facilities Surcharge Mechanism, or FSM, to be calculated separately from and incrementally to the then-existing surcharges in its tariff rates. The FSM includes additional projects negotiated and agreed upon between Lakehead and CAPP as a transparent, cost-of-service based tariff mechanism. This allows the Lakehead system to recover the costs associated with particular shipper-requested projects through an incremental surcharge layered on top of the existing base rates. The FSM Settlement requires the Lakehead system to adjust the FSM annually to reflect the latest estimates for the upcoming year and to adjust for the difference between estimates and actual cost and throughput data from the prior year.

The FERC permitted the FSM to take effect as of July 1, 2004, and the FSM was expressly designed to be open-ended. In its approval of the FSM Settlement, the FERC accepted the Lakehead system's proposal "to submit for FERC review and approval future agreements resulting from negotiations with CAPP where the parties have agreed that recovery of costs through the FSM is desirable and appropriate." At the time it was initially established, four projects were included in the FSM. Over the course of several years, the FERC subsequently approved the addition of new projects to the FSM, and as of December 31, 2015, 24 projects are included in the FSM.

On August 14, 2008, the FERC approved an Amendment to the FSM Settlement to allow the Lakehead system to include in the FSM particular shipper-requested projects that are not yet in service as of April 1 of each year, provided there is an annual adjustment for differences between actual and estimated throughput and costs.

On December 1, 2014, Enbridge filed a Supplement to the Settlement in Docket No. OR15-4-000 seeking approval for the recovery of the costs associated with the "2015-16 Mainline and Eastern Access Expansions" projects in future tariff filings. The FERC accepted the Supplement on February 2, 2015, which included the following projects:

a) Expansion of Alberta Clipper, or Line 67, from 570,000 Bpd to 800,000 Bpd. It includes four new pump stations and modifications at three existing pump stations;

b) Expansion of Southern Access, or Line 61, from 560,000 Bpd to 1,200,000 Bpd. It includes new pump stations; modifications at four existing pump stations; and tanks at Flanagan, Illinois, and Superior, Wisconsin;

c) Expansion of Line 6B from 500,000 Bpd to 570,000 Bpd. It includes modifications at existing pump stations and terminal upgrades; and

d) Construction of Line 78, a twin of our existing Line 62, with an initial capacity of 570,000 Bpd. The new 36-inch pipeline from Flanagan, Illinois to Hartsdale, Indiana includes a new initiating pump station.

On December 19, 2014, Flint Hills Resources, L.P., or Flint, filed a Motion to Intervene and Request for Clarification or, In the Alternative Protest, and on December 29, 2014, Suncor Energy Marketing Inc., or Suncor, filed a Motion to Intervene and Protest the Supplement filing. Suncor requested that the FERC defer action on the Supplement until after Lakehead filed a tariff incorporating the new project and that the tariff be allowed to go into effect subject to refund. On January 8, 2015, Enbridge filed a Reply to Flint's Request for Clarification and Suncor's Protest. Enbridge addressed the issues raised and requested that the FERC approve the FSM Supplement. On February 2, 2015, the FERC accepted the Supplement to the Settlement in Docket No. OR15-4-000 to permit the recovery of costs associated with the 2015-16 Mainline and Eastern Access Expansions projects.

On February 27, 2015, Enbridge filed FERC tariff 43.16.0 which included the costs related to the expansion of Line 67 to 800,000 Bpd, the expansion of Line 61 to 800,000 Bpd and the construction of Line 78.

The Lakehead system was subject to one protest in 2015 in relation to FERC tariff 43.16.0. Suncor filed a protest on March 16, 2015, claiming that Enbridge had used an outdated base capacity that would result in an over-collection of approximately $94.6 million per year, and therefore that the rates were unjust and unreasonable. Enbridge filed a response on March 20, 2015, stating that the FSM calculation methodology was correct and has remained unchanged since its inception in 2004, and thus that Suncor's protest was invalid. On March 31, 2015, the FERC issued an order dismissing Suncor's protest and accepting the tariff filing. On April 30, 2015, Suncor filed a Request for Rehearing, and on August 18, 2015, the FERC issued an Order Denying Rehearing.

On December 15, 2015, Enbridge filed a Supplement to the Settlement in Docket No. OR16-9-000 seeking approval for the recovery of a negotiated amount for the costs associated with the ''Interim Lakehead Operational Tank Service'' project. This project permits the recovery of a negotiated cost of $1.5 million per month for the provision of tank service.

As of December 31, 2015, the FSM was $1.0515 per barrel for light crude oil movements from the Canada-United States international border near Neche, North Dakota to Chicago, Illinois.

International Joint Tariff

FERC Tariff No. 45.7.0, issued May 29, 2015, revised the International Joint Tariff, or IJT, effective July 1, 2015, by increasing the transportation tolls by 1.42%. The IJT provides rates applicable to the transportation of petroleum from all receipt points in western Canada on the Enbridge Pipelines Inc., or Enbridge Pipelines, Canadian Mainline system to all delivery points on the Lakehead Pipeline system owned by Enbridge Energy and to delivery points on the Canadian Mainline located downstream of the Lakehead system. In summary, the IJT provides a simplified tolling structure to cover transportation services that cross the international border and provides a rate that is equal to or less than the sum of the combined Canadian Mainline and Lakehead system rates on file and in effect.

Mid-Continent system

Our Ozark system is located in the Mid-Continent region of the United States. Specifically, the system originates in Cushing, Oklahoma, and offers transportation service to Wood River, Illinois.

Effective July 1, 2015, our Ozark system filed FERC Tariff 48.5.0 to increase its rate in compliance with the indexed rate ceilings allowed by the FERC by incorporating the multiplier of 1.045829 that was issued by the FERC in Docket No. RM93-11-000 on May 14, 2015.

Effective December 1, 2015, our Ozark system filed FERC Tariff 48.6.0 to increase its rate from $0.6759 to $0.8403. This filing was made to allow for recovery of costs related to the capital expenditures required to maintain the integrity of the pipeline.

The transportation rate for light crude oil on our Ozark system is set forth below:

	Published Transportation Rate Per Barrel[(1)(2)]
From Cushing, Oklahoma to Wood River, Illinois	$0.8403

(1) Pursuant to FERC Tariff No. 48.6.0 as filed with the FERC on October 30, 2015, with an effective date of December 1, 2015.

(2) The transportation rates apply to light crude oil only. Medium and heavy crude oil transportation rates on the system are higher.

North Dakota system

The North Dakota system consists of both gathering and trunkline assets. Effective January 1, 2008, the looping surcharge was implemented as a part of the North Dakota Phase 5 expansion program, referred to as North Dakota Phase 5. The Phase 5 Offer of Settlement that was filed with the FERC for an expansion of the system was approved by the Commission on October 31, 2006 in Docket No. OR06-9-000. The Phase 5 Offer of Settlement outlined the looping surcharge as a cost-of-service based surcharge that is adjusted each year for differences between estimated and actual costs and volumes and is not subject to the FERC indexing methodology. This surcharge was initially applicable for five years immediately following the in-service date of North Dakota Phase 5, which was January 2008. The looping surcharge is applied to volumes originating at Trenton, Little Muddy or Alexander, North Dakota. Effective April 1, 2010, the term of the looping surcharge on our North Dakota system was extended by four years, ending on December 31, 2016. The impact of the term extension reduced the looping surcharge substantially thereby moderating the rate impact on shippers.

The FERC approved the Phase 6 expansion Offer of Settlement submitted by Enbridge North Dakota on October 20, 2008, in Docket No. OR08-6-000. Under the terms of the settlement, expansion costs are recovered through a cost-of-service based surcharge on all shipments to Clearbrook, Minnesota. The surcharge is in addition to existing base rates and the Phase 5 surcharges and is adjusted on an annual basis to actual costs and volumes. It is not subject to the FERC index methodology. The Phase 6 surcharge became effective on January 1, 2010 and will expire on December 31, 2016.

On August 26, 2010, the North Dakota system and Enbridge Pipelines (Bakken) L.P. filed a Petition for Declaratory Order seeking the approval of priority service for the North Dakota portion of the Bakken Project as well as the overall tariff and rate structure for the United States portions of the program. The Petition for Declaratory Order was approved by the FERC on November 22, 2010 in Docket No. OR10-19-000, and the Bakken Project went into service on March 1, 2013.

On November 2, 2012, the North Dakota system submitted a Petition for Declaratory Order seeking approval of a related Offer of Settlement with respect to a major expansion and extension of the North Dakota system called the Sandpiper Project. The project will result in a substantial increase in the capacity available to transport Bakken crude both to and through Clearbrook, Minnesota to Superior, Wisconsin. The terms of the proposal include, among other things, the addition of a cost-of-service rate surcharge to the existing rates to Clearbrook, and a new cost-of-service tariff rate from Clearbrook to Superior. On March 22, 2013, the Petition was denied by the FERC on the basis that an Offer of Settlement requires the unanimous approval of all shippers. A revised proposal for the Sandpiper Project, including the availability of contracted space on the pipeline, is currently being offered to shippers through a successful open season and on February 19, 2014, a revised Petition for Declaratory Order was filed with the FERC. In this petition, the North Dakota system proposed a tariff structure that involves separate rates for committed priority volumes, committed non-priority volumes, and uncommitted volumes. On May 15, 2014, the Petition for Declaratory Order was approved by the FERC in Docket No. OR14-21-000.

Effective February 1, 2015, FERC tariff No. 3.6.0 established a new interconnection at Tioga, North Dakota.

Effective April 1, 2015, FERC tariff No. 3.7.0 updated the calculation of the Phase 5 Looping and Phase 6 Mainline surcharges. These surcharges are cost-of-service based surcharges that are adjusted each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing decreased our average transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.44 per barrel, to an average of approximately $1.77 per barrel. The Phase 5 Looping surcharge decreased primarily due to an increase in forecasted throughput, and the Phase 6 Mainline surcharge decreased due to an increase in forecasted throughput and in order to return prior period over-recoveries to shippers.

Effective April 22, 2015, FERC tariff No. 3.8.0 cancelled the transportation rate from Sherwood, North Dakota to Clearbrook, Minnesota, as the pipeline no longer provides service from that receipt point.

Effective July 1, 2015, FERC tariff No. 3.10.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015, in Docket No. RM93-11-000. Additionally, as per the Transportation Services Agreement, or TSA, this tariff adjusted the operating cost charge component of the committed trunkline rates to Berthold, North Dakota to the actual operating costs and throughput volumes for 2014 and the forecasted operating costs and throughput for 2015.

Also effective July 1, 2015, FERC tariff No. 3.11.0 discounted the existing uncommitted rate from Berthold (pump-over), North Dakota to Berthold, North Dakota. The new tariff rate of $0.27 per barrel reflects a rate decrease of $0.556 per barrel.

Effective December 1, 2015, FERC tariff 3.13.0 was filed to establish an initial gathering service and charge at Little Muddy (Williams County), North Dakota. The $0.1137 per barrel interconnection rate resulted from a shipper's request for a pipeline interconnection at that location.

Effective December 16, 2015, FERC tariff 3.15.0 was filed to cancel trunkline transportation rates from Glenburn (Renville County), North Dakota and Newburg (Bottineau County), North Dakota to Clearbrook (Clearwater County), Minnesota, as well as to cancel the gathering rate from Newburg Area, North Dakota to Newburg (Bottineau County), North Dakota, as the pipeline is no longer providing service from those receipt points.

The rates and surcharges for transportation of light crude oil on our North Dakota system are set forth below:

	Published Transportation Rate Per Barrel(1)
From Minot, Berthold and Stanley, North Dakota to Clearbrook, Minnesota	$1.5269
From Grenora, North Dakota to Clearbrook, Minnesota	$1.6920
From Reserve, Montana to Clearbrook, Minnesota	$1.7285
From Tioga, North Dakota to Clearbrook, Minnesota	$1.5631
From Trenton, North Dakota to Clearbrook, Minnesota	$2.0705
From Alexander, North Dakota to Clearbrook, Minnesota	$2.1251
From Little Muddy, North Dakota to Clearbrook, Minnesota	$2.0705
From Grenora, North Dakota to Tioga, North Dakota	$0.6420
From Reserve, Montana to Tioga, North Dakota	$0.6785
From Trenton, North Dakota to Tioga, North Dakota	$0.8736
From Alexander, North Dakota to Tioga, North Dakota	$0.9281
From Little Muddy, North Dakota to Tioga, North Dakota	$0.8736
From (pump-over) Stanley, North Dakota to Stanley, North Dakota	$0.2842
From Tioga, North Dakota to Stanley, North Dakota	$1.0400
From Grenora, North Dakota to Stanley, North Dakota	$1.1881
From Reserve, Montana to Stanley, North Dakota	$1.2217
From Trenton, North Dakota to Stanley, North Dakota	$1.5519
From Alexander, North Dakota to Stanley, North Dakota	$1.6023
From Little Muddy, North Dakota to Stanley, North Dakota	$1.5519
From Berthold, North Dakota to Berthold, North Dakota	$0.2700
From Stanley, North Dakota to Berthold, North Dakota	$0.9491
From Tioga, North Dakota to Berthold, North Dakota	$1.0400

(1) Pursuant to FERC Tariff No. 3.15.1 as filed with the FERC on December 15, 2015, with an effective date of December 16, 2015.

Bakken System

As previously mentioned, the North Dakota system and Enbridge Pipelines (Bakken) L.P. filed a Petition for Declaratory Order seeking approval to provide priority service for the North Dakota portion of the Bakken pipeline as well as the overall tariff and rate structure for the U.S. portions of the Bakken pipeline. The Petition for Declaratory Order was approved by the FERC on November 22, 2010 in Docket No. OR10-19-000, and the Bakken pipeline went into service on March 1, 2013.

Local Tariff

Effective July 1, 2014, the North Dakota system filed on behalf of the Bakken system FERC tariff 2.1.0. The tariff increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporated the multiplier of 1.038858 issued by the FERC on May 14, 2014 in Docket No. RM93-11-000.

Effective July 1, 2015, the North Dakota system filed on behalf of the Bakken system FERC tariff 2.2.0. The tariff increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporated the multiplier of 1.045829 issued by the FERC on May 14, 2015, in Docket No. RM93-11-000.

The rates and surcharges for transportation of light crude oil on our Bakken system are set forth below:

	Published Transportation Rate Per Barrel[(1)]
From Berthold, North Dakota to the international border near Portal, North Dakota	$1.2990

(1) Pursuant to FERC Tariff No. 2.2.0 as filed with the FERC on May 29, 2015, with an effective date of July 1, 2015.

International Joint Tariff

Effective July 1, 2014, the Bakken system filed FERC tariff 3.1.0. This filing was a compliance filing in accordance with transportation service agreements included in the Petition for Declaratory Order filed on August 26, 2010 in Docket No. OR10-10-000. This filing also included an adjustment for the operating cost charge, which is part of the committed rate structure. The committed rate structure consists of two components — a based committed rate and an operating cost charge. The operating cost charge is a flow-through of the related operating costs, and is based on throughput. The initial operating costs charge at the in-service date for Bakken on March 1, 2013, was $0.33. With the aforementioned filing, the operating costs charge decreased to $0.24.

Effective July 1, 2015, the Bakken system filed FERC tariff 3.4.1. This filing was a compliance filing in accordance with transportation service agreements included in the Petition for Declaratory Order filed on August 26, 2010 in Docket No. OR10-19-000. The operating cost charge for Bakken as of July 1, 2015, decreased by $0.36 to a credit of $0.12 as an adjustment for an over recovery in the prior year.

Safety Regulation and Environmental

General

Our transmission and gathering pipelines, storage and processing facilities, trucking and railcar operations are subject to extensive environmental, operational and safety regulation at the federal and state level. 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

Our transmission and gathering pipelines are subject to regulation by the DOT and PHMSA under the Pipeline Safety Act, or PSA, specifically Volume 49 of the Code of Federal Regulations, Parts 192 (gas) and 195 (hazardous liquids). The regulations pertain to the design, installation, testing, construction, operation, replacement and management of transmission and gathering pipeline facilities. PHMSA is the agency charged with regulating the safe transportation of hazardous materials under all modes of transportation, including interstate and intrastate pipelines. Periodically the PSA has been reauthorized and amended, imposing new mandates on the regulator to promulgate new regulations and imposing direct mandates on operators of pipelines.

We have incorporated all existing requirements into our programs by the required regulatory deadlines, and are continually incorporating any 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, or NTSB, may perform an investigation of a significant accident to determine the probable cause and issue safety recommendations to prevent future accidents. Any release that results in an enforcement action or NTSB investigation, such as those associated with Line 6B near Marshall, Michigan and Line 14 near Grand Marsh, Wisconsin, could have a material impact on system throughput or compliance costs. As part of the Corrective Action Order, or CAO, related to the Grand Marsh release, we were required to develop and implement a comprehensive plan to address wide-ranging safety initiatives not only for Line 14, but for our entire Lakehead System.

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 Clean Air Act, or CAA, and the 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. The operations of our pipeline facilities are subject to the Environmental Protection Agency's, or EPA, Spill Prevention, Control, and Countermeasures Rule and we are currently in full compliance. Our facilities subject to existing EPA Greenhouse Gas Reporting rules have reported emissions prior to the annual filing deadlines.

On October 31, 2014, the Texas State Implementation Plan received the authority to regulate greenhouse gas emissions and approve Greenhouse Gas Prevention of Significant Deterioration, or GHG PSD, permits in Texas. This approval authority should simplify the GHG PSD permitting process in Texas. On November 10, 2014, the EPA rescinded a Federal Implementation Plan, or FIP, for Texas for GHG PSD permitting.

The EPA published its final New Source Performance Standards, or NSPS, Subpart OOOO and National Emission Standards for Hazardous Air Pollutants, or NESHAP, Subpart HHH, for volatile organic compounds, or VOCs, and sulfur dioxide, or SO2, emissions from the oil and natural gas sector, which became effective on August 16, 2012. On September 18, 2015, the EPA published a proposed rule, Subpart OOOOa, which would update the original 2012 standards to include additional reductions in methane and VOCs in the oil and gas industry. On November 26, 2014, the EPA announced its intentions to strengthen air quality standards to within a range of 65 to 70 parts per billion, or Ppb, for ozone. The EPA last updated these standards in 2008, then setting the standard at 75 Ppb. On October 1, 2015, the EPA strengthened the National Ambient Air Quality Standards, or NAAQS, for ground-level ozone to 70 Ppb. As a result of the more stringent standard, numerous counties fall into the non-attainment category, resulting in more costly pollution control requirements.

On October 22, 2015, the EPA responded to a petition made by the Environmental Integrity Project to include the oil and gas extraction industrial sector in the scope of covered sectors of Section 313 of the Emergency Planning and Community Right-to-Know Act, commonly known as the Toxic Release Inventory, or TRI. The EPA's response stated that natural gas processing facilities may be appropriate for addition to the scope of the TRI and will likely commence the rulemaking process to include these facilities in the reporting requirements. We operate facilities that may be impacted by this change, if implemented.

For all proposed rules, we will continue to track the progress through involvement in industry groups and will comply with regulatory requirements. We do not expect a material effect on our financial statements as a result of compliance efforts.

On June 29, 2015, the EPA published the Clean Water Rule: Definition of ''Waters of the United States.'' The new rule is intended to clarify what is considered Waters of the United States, or WOTUS, with respect to discharges of pollutants to the covered water. 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 our 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 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 crude oil, 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

Neither we nor Enbridge Management have any employees. Our General Partner has delegated to Enbridge Management, pursuant to a delegation of control agreement, substantially all of the responsibility for our day-to-day management and operation. Our General Partner, however, retains certain functions and approval rights over our operations. To fulfill its management obligations, Enbridge Management has entered into agreements with Enbridge and several of its affiliates to provide Enbridge Management with the necessary services and support personnel who act on Enbridge Management's behalf as its agents. We are ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

INSURANCE

Our operations are subject to many hazards inherent in the liquid petroleum and natural gas gathering, treating, processing and transportation 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 maintain commercial liability insurance coverage that is consistent with coverage considered customary for our industry. We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries through the policy renewal date of May 1, 2016. The insurance coverage also includes property insurance coverage on our assets that includes earnings interruption resulting from an insurable event, except for 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 we have entered into with Enbridge and other Enbridge subsidiaries.

The coverage limits and deductible amounts at December 31, 2015 for our insurance policies:

Insurance Type	Coverage Limits	Deductible Amount
	(in millions)	
Property and business interruption	Up to $800.0	$10.0
General liability	Up to $860.0	$ 0.1
Pollution liability (as included under General Liability)	Up to $860.0	$30.0

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.enbridgepartners.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 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

Our actual 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 maintain or increase cash distributions.

Our strategy 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, permitting at federal, state and local levels, as well as 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 currently 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 needed or may adversely affect our future results of operations and cash flows.

Our revenues and cash flows may not increase immediately on 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. In addition, circumstances may occur from time to time, such as the inability to obtain a necessary permit, which could cause us to cancel a project. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays, project cancellations 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 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 prevalent during the recessionary period of 2008 that continued for several years as well as the current decline in commodity prices, 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.

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.

A downgrade in our credit rating could require us to provide collateral for our hedging liabilities and negatively impact our interest costs and borrowing capacity under our Credit Facilities.

Standard & Poor's, or S&P, Dominion Bond Rating System, or DBRS, and Moody's Investors Service, or Moody's, rate our non-credit enhanced, senior unsecured debt. Although we are not aware of current plans by the ratings agencies to lower their respective ratings on such debt, we cannot be assured that such credit ratings will not be downgraded.

Currently, we are parties 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 us to provide assurances of performance if our counterparties' exposure to us exceeds certain levels or thresholds. We generally provide letters of credit to satisfy such requirements. At December 31, 2015, we have provided $120.1 million in the form of letters of credit as assurances of performance for our then outstanding derivative financial instruments. In the event that our credit ratings were to decline to the lowest level of investment grade, as determined by S&P and Moody's, we would be required to provide letters of credit in substantially greater amounts to satisfy the requirements of our ISDA® agreements. For example, if our credit ratings had been at the lowest level of investment grade at December 31, 2015, we would have been required to provide additional letters of credit in the aggregate amount of $52.5 million. The amounts of any letters of credit we would have to establish under the terms of our ISDA® agreements would reduce the amount that we are able to borrow under our senior unsecured revolving credit facility and our 364-day credit facility, referred to as our Credit Facilities.

We may not have sufficient cash flows to enable us to continue to pay distributions at the current level.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay distributions at the current level. The amount of cash we are able to distribute depends on the amount of cash we generate from our operations, which can fluctuate quarterly based upon a number of factors, including:

- the operating performances of our assets;
- commodity prices;
- our ability to bring new assets into service at its expected time and projected cost;
- actions of governmental regulatory bodies;
- the level of capital expenditures we make;
- the amount of cash reserves established by Enbridge Management;
- our ability to access capital markets and borrow money;
- our debt service requirements and restrictions in our credit agreements;
- the ability of MEP to make distributions to us;
- fluctuations in our working capital needs; and
- the cost of acquisitions.

In addition, the amount of cash we distribute depends primarily on our cash flow rather than net income or net loss. Therefore, we may make cash distributions for periods in which we record net losses or may make no distributions for periods in which we record net income.

Our acquisition strategy may be unsuccessful if we incorrectly predict operating results, are unable to identify and complete future acquisitions and integrate acquired assets or businesses.

The acquisition of complementary energy delivery assets is a component of our strategy. Acquisitions present various risks and challenges, including:

- the risk of incorrect assumptions regarding the future results of the acquired operations or expected cost reductions or other synergies expected to be realized as a result of acquiring such operations;
- a decrease in liquidity as a result of utilizing significant amounts of available cash or borrowing capacity to finance an acquisition;
- the loss of critical customers or employees at the acquired business;

- the assumption of unknown liabilities for which we are not fully and adequately indemnified;
- 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 or consummate acquisitions in the future.

Our financial performance could be adversely affected if our pipeline systems are used less.

Our financial performance depends to a large extent on the volumes transported on our liquids or natural gas pipeline systems. Decreases in the volumes transported by our systems can directly and adversely affect our revenues and results of operations. The volume transported on our pipelines can be influenced by factors beyond our control including:

- competition;
- regulatory action;
- weather conditions;
- storage levels;
- alternative energy sources;
- decreased demand;
- fluctuations in energy commodity prices;
- environmental or other governmental regulations;
- economic conditions;
- supply disruptions;
- availability of supply connected to our pipeline systems; and
- availability and adequacy of infrastructure to move, treat and process supply into and out of our systems.

As an example, the volume of shipments on our Lakehead system depends heavily on the supplies of western Canadian crude oil. Insufficient supplies of western Canadian crude oil will adversely affect our business by limiting shipments on our Lakehead system. Decreases in conventional crude oil exploration and production activities in western Canada and other factors, including supply disruption, higher development costs and competition, can slow the rate of growth of our Lakehead system. The volume of crude oil that we transport on our Lakehead system, as well as the North Dakota and Bakken systems, also depends on the demand for crude oil in the Great Lakes and Midwest regions of the United States and the volumes of crude oil and refined products delivered by others into these regions and the province of Ontario. As well, there are supply driven risks around our North Dakota and Bakken assets, as lower commodity prices can reduce drilling and volumes on our systems.

In addition, our ability to increase deliveries to expand our Lakehead system in the future depends on increased supplies of western Canadian crude oil. We expect that growth in future supplies of western Canadian crude oil will come from oil sands projects in Alberta. Full utilization of additional capacity as a result of our Alberta Clipper and Southern Access pipelines and future expansions of our Lakehead system will largely depend on these anticipated increases in crude oil production from oil sands projects. A reduction in demand for crude oil or a decline in crude oil prices may make certain oil sands projects uneconomical since development costs for production of crude oil from oil sands is greater than development costs for production of conventional crude oil. Oil sands producers may cancel or delay plans to expand their facilities, as some oil sands producers have done in recent years, if crude oil prices are at levels that do not support expansion. Any cancellation or delay of oil sands projects could directly impact our Lakehead system with potential indirect impacts on our Mid-Continent, North Dakota and Bakken systems. Additionally, measures adopted by the government of the province of Alberta to increase its share of revenues from oil sands development coupled with a decline in crude oil prices could reduce the volume growth we have anticipated in expanding the capacity of our crude oil pipelines.

The volume of shipments on natural gas and NGL systems depends on the supply of natural gas and NGLs available for shipment from the producing regions that supply these systems. Supply available for shipment can be affected by many factors, including commodity prices, weather and drilling activity among other factors listed above. Volumes shipped on these systems are also affected by the demand for natural gas and NGLs in the markets these systems serve. Existing customers may not extend their contracts for a variety of reasons, including a decline in the availability of natural gas from our 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 the natural gas systems were to render the delivered cost of natural gas on our systems uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Our financial performance may be adversely affected by risks associated with the Alberta oil sands.

Our Lakehead system is highly dependent on sustained production from the Alberta oil sands. Growth in production from the oil sands over the past decade has remained strong due to high oil prices and improved production methods; however the industry faces a number of risks associated with the scope and scale of its projects. Factors and risks affecting the oil sands industry include:

- reduced crude oil prices;
- cost inflation;
- labor availability;
- environmental impact;
- reputation management;
- changing policy and regulation; and
- commodity price volatility.

Alberta oil sands producers face a number of challenges that must be managed effectively to allow for sustained growth in the sector. The unprecedented level of development in the Alberta oil sands has driven costs upward as a result of a tight labor market, high equipment costs, and costs for commodities such as steel and other raw materials. Labor has been one of the most important considerations for the industry, as worker wages have risen steadily with industry development over the past several years.

The environmental impact of oil sands development in northern Alberta has been at the forefront of discussion around future industry growth in the region. Labor and environmental groups have expressed their views and concerns about oil sands development and pipeline infrastructure in the public domain and in front of regulators. The primary concerns raised include greenhouse gas emissions and environmental monitoring and reclamation. Though industry associations have stated that they are not opposed to changes in policy and regulation to address these concerns, the adoption of new regulation that may curtail oil sands development or adversely impact the oil and gas industry remains a risk and may result in, among other things, significant capital expenditures, increased operating costs, or decreased demand for our products.

Competition may reduce our revenues.

Our Lakehead system faces current and potentially further competition from other pipelines for transporting western Canadian crude oil, which may reduce our volumes and the associated revenues. To the extent that the rate is calculated using a cost-of-service methodology, these lower volumes will increase our transportation rates. The increase in transportation rates could result in rates that are higher than competitive conditions will otherwise permit. Our Lakehead system competes with other crude oil and refined product pipelines and other methods of delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Chicago, Detroit, Toledo, Buffalo, and Sarnia, and the refinery market and pipeline hub located in the Patoka/Wood River area of southern Illinois. Refineries in the markets served by our Lakehead system compete with refineries in western Canada, the province of Ontario and the Rocky Mountain region of the United States for supplies of western Canadian crude oil.

Our Ozark pipeline system faces competition from a competitor pipeline that carries crude oil from Hardisty to Wood River and Patoka in southern Illinois.

Our North Dakota system faces competition from rail transportation driven by limited transportation infrastructure to key markets. Further, recently announced pipeline projects by competitors are supported by contracts and take-or-pay arrangements, which increases the competitive pressure on our North Dakota system.

We also encounter competition in our natural gas gathering, treating, and processing and transmission businesses. A number of new interstate natural gas transmission pipelines being constructed could reduce the revenue we derive from the intrastate transmission of natural gas. 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 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.

Our gas marketing operations involve market and regulatory risks.

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

- our ability to negotiate on a timely basis natural gas 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, NGL or condensate 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, NGLs or condensate on comparable terms;
- changes in, limitations upon or elimination of the regulatory authorization required for our wholesale sales of natural gas, NGLs and condensate in interstate commerce; and
- long-term commitments on third-party pipelines, storage facilities or fractionation agreements that are above market prices and may go unutilized.

Our Liquids segment results may be adversely affected by commodity price volatility.

Volatility in commodity prices can impact production volumes in the oil sands region of Western Canada and the Bakken region of North Dakota, our two primary crude oil supply basins.

The relatively high costs and large up front capital investments required by oil sands projects involves significant assumptions concerning short-term and long-term crude oil fundamentals including world supply and demand, North American supply and demand, and price outlook among many other factors. As oil sands production is long-term in nature, the long-term outlook is significant to a producer's investment decision. These decisions may impact the annual rate of future supply growth from the oil sands region.

While current oil sands projects are not as sensitive to short-term declines in crude oil prices, a protracted decline in crude oil prices could result in delay or cancellation of future projects. In addition, wide commodity price spreads have impacted producer netbacks and margins in the past years that largely resulted from insufficient pipeline infrastructure and takeaway capacity from producing regions in Alberta. Combined with high labor and operating costs, this has forced some producers to reconsider or defer projects until a more favorable climate for infrastructure development can be forecast.

Tight sands and shale oil production in any basin in North America such as the Bakken or the Permian will be comparatively more sensitive to the short-term changes in crude oil prices due to the sharp declining production profile associated with individual tight sands and shale oil wells. Accordingly, during periods of comparatively low prices, supply growth from the North Dakota basin may be lower, which may impact volumes on our pipeline system.

Our Natural Gas segment results may be adversely affected by commodity price volatility and risks associated with our hedging activities.

Our industry remains in a weak commodity price cycle, which could extend beyond 2016. Our exposure to commodity price volatility is inherent to our natural gas processing activities. Before hedging, approximately 40% of our gross margin attributable to our natural gas processing activities is expected to be attributable to contracts with some degree of commodity price exposure in 2016. MEP employs a disciplined hedging program to manage this direct commodity price risk.

To the extent that we engage in hedging activities to reduce our commodity price exposure in 2016, 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 adversely affect our results of operation and cash flows and ability to make distributions.

Additionally, our hedging activities may not be as effective as we intend in reducing the volatility of our 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.

Changes in, or challenges to, our rates 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 FERC or state regulatory agencies, or both. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates, 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.

We believe that the rates we charge for transportation services on our interstate common carrier oil and open access natural gas pipelines are just and reasonable under the ICA and NGA, respectively. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, or a regulator's own initiative, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier oil and open access natural gas pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Increased regulation and regulatory scrutiny may reduce our revenues.

Our interstate pipelines and certain activities of our intrastate natural gas pipelines are subject to FERC regulation of terms and conditions of service. In the case of interstate natural gas pipelines, FERC also establishes requirements respecting the construction and abandonment of pipeline facilities. FERC has pending proposals to increase posting and other compliance requirements applicable to natural gas markets. Such changes could prompt an increase in FERC regulatory oversight of our pipelines and additional legislation that could increase our FERC regulatory compliance costs and decrease the net income generated by our pipeline systems.

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 laws and 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, oftentimes imposing complex requirements and necessitating capital expenditures or increased operating costs to achieve compliance, especially when activity is in the presence of sensitive elements like water crossings, wetlands and endangered species. 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 operation of liquid petroleum and natural gas gathering, processing, treating and transportation facilities exposes us to the risk of incurring significant environmental and safety-related costs and liabilities. Additionally, operational modifications, including pipeline restrictions, necessary to comply with regulatory requirements and resulting from our handling of liquid petroleum and natural gas, 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. Further, environmental and operational safety laws and regulations, including but not limited to pipeline safety, wastewater discharge and air emission requirements, continue to become more stringent over time, particularly those related to the oil and gas industry. We may incur joint and several strict liability under these environmental laws and regulations in connection with discharges or releases of liquid petroleum and natural gas 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, oftentimes by third parties not under our control. Private parties, including the owners of properties through which our gathering systems pass and facilities where our liquid petroleum and natural gas 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. In addition, the regulation of greenhouse gas emissions could result in less demand for crude oil, natural gas and NGLs over time. At the federal level, the United States Congress has in the past and may in the future consider legislation to impose a tax on carbon or require a reduction of greenhouse gas emissions. 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 the EPA's mandatory greenhouse gas emissions reporting requirements to include petroleum and natural gas systems. These regulations were amended by the EPA in November 2014.

The EPA concluded that 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 CAA that, in general, potentially could 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 establish the greenhouse gas emissions threshold for major new (and major modifications to existing) stationary sources. This rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit (Coalition for Responsible Regulation v. EPA), which dismissed the challenge on jurisdictional grounds. On appeal, the U.S. Supreme Court in 2013 (Utility Air Regulatory Group v. EPA) found the rule to be unlawful. Under the approach now being implemented by the EPA, for most purposes, new permitting provisions to control greenhouse gas emissions are required for new major source facilities that also emit 100,000 tons per year or more of carbon dioxide equivalent, or CO2e, and existing major source facilities making major modifications that also 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. In August 2015, the EPA proposed regulations to reduce methane and other greenhouse gas emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025. The proposed rule would impose additional costs related to compliance with the new emission limits as well as inspections and maintenance of several types of equipment used in our operations.

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 take direct measures to further reduce greenhouse gas emissions or purchase and surrender emission allowances. 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.

Increased regulation of hydraulic fracturing and related activities 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, have been proposed in Congress. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential impacts of hydraulic fracturing on drinking water resources; the multi-year study's individual research projects began publishing results in 2013, and individual studies are ongoing. In addition, the EPA has announced its intention to regulate wastewater discharges from hydraulic fracturing and other natural gas production activities under the CWA and in a proposed rule published on April 7, 2015. The EPA anticipates finalizing this rule by August 2016. The Department of Interior also issued new regulations governing hydraulic fracturing on public and tribal lands that may impose additional operating costs. The impact of this rule is uncertain because it is subject to ongoing litigation and is currently enjoined pursuant to a court order.

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 producing plants, and certain other equipment. On April 12, 2013, the 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.

Future regulatory actions also have the potential to impact our operations. In August 2015, the EPA issued proposed options that would clarify the definition of ''adjacent'' sources of pollution in the context of the Clean Air Act permitting requirements for the oil and gas sector. This action could result in additional permitting burdens under the EPA's Prevention of Significant Deterioration, Nonattainment New Source Review, and Title V permitting programs. The Pipeline and Hazardous Materials Safety Administration also has announced its intention to propose rules in 2016 that could, when finalized, require us to, among other things, upgrade our automatic shut-off valves at our facilities. Finally, in October 2015, the EPA proposed to reduce the National Ambient Air Quality Standard for ozone from 75 Ppb to 70 Ppb. Once final, this regulation could impose additional emissions control costs on our operations.

These rules and proposals 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 TRRC 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. Certain states, including the State of Texas, also have taken regulatory action in response to increased seismic activity that in certain cases has been connected to hydraulic fracturing or to saltwater or drilling fluid disposal wells. In addition, at least one municipality in a state in which we operate, the City of Denton, Texas, has followed others in adopting bans or severely restricting hydraulic fracturing activities. Litigation concerning this ban, as well as others, is ongoing. We cannot predict whether any legislation or regulation 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, state or local level, it 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 and adversely affect our financial condition, results of operations and cash flows, as well as our ability to make cash distributions to our unitholders.

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.

United States based oil sands development opponents as well as others concerned with environmental impacts of pipeline routes advocated by our competitors have utilized political pressure to influence the timing and whether such permits are granted which could impact future pipeline development.

Our assets vary in age and were constructed over many decades which may cause our inspection, maintenance or repair costs to increase in the future. In addition, there could be service interruptions due to unknown events or conditions, or increased downtime associated with our pipelines that could have a material and adverse effect on our business and results of operations.

Our pipelines vary in age and were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have changed over time. Depending on the era of construction, some assets will require more frequent inspections, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make distributions to our unitholders. As well, there could be service interruptions due to unknown events or conditions, or increased downtime associated with our pipelines that could have a material and adverse effect on our business and financial results.

Measurement adjustments on our pipeline system can be materially impacted by changes in estimation, commodity prices and other factors.

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum pipelines. The three types of oil measurement adjustments that routinely occur on our systems include:

- physical, which results from evaporation, shrinkage, differences in measurement (including sediment and water measurement) between receipt and delivery locations and other operational conditions;
- degradation resulting from mixing at the interface within our pipeline systems or terminals and storage facilities between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation, which is a function of crude oil prices, the level of our carriers' inventory and the inventory positions of customers.

Quantifying oil measurement adjustments is inherently difficult because physical measurements of volumes are not practical as products continuously move through our pipelines and virtually all of our pipeline systems are located underground. In our case, measuring and quantifying oil measurement losses is especially difficult because of the length of our pipeline systems and the number of different grades of crude oil and types of crude oil products we transport. Accordingly, we utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses.

Natural gas measurement adjustments occur as part of the normal operating conditions associated with our natural gas 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 natural gas systems, primarily around our gathering and processing assets; (2) varying qualities of natural gas 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 natural gas systems.

We do not own a majority of the land on which our pipelines are located, which could result in increased costs and 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 (including but not limited to Native American lands), and some of our agreements may grant us those rights for only a specific period of time. We are unable to predict the outcome of discussions with third parties, the governmental agencies, the appropriate Native American tribes, the tribes' governing bodies, or the United States Bureau of Indian Affairs with respect to future arrangements or changes in applicable laws and the resulting costs, fees, bonds and taxes related to these leases, easements and rights-of-way, or grants of land rights. 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 attacks and threats, escalation of military activity in response to these attacks or acts of war, and other civil unrest or activism could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, escalation of military activity or acts of war, or other civil unrest or activism 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 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. In addition, increased environmental activism against pipeline construction and operation could potentially result in work delays, reduced demand for our products and services, increased legislation or denial or delay of permits and rights-of-way. Finally, the disruption or a significant increase 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.

Cyber-attacks or security breaches could have a material adverse effect on our business, financial condition or results of operations.

Our business is dependent upon information systems and other digital technologies for controlling our plants and pipelines, processing transactions and summarizing and reporting results of operations. The secure processing, maintenance and transmission of information is critical to our operations. A security breach of our network or systems could result in improper operation of our assets, potentially including delays in the delivery or availability of our customers' products, contamination or degradation of the products we transport, store or distribute, or releases of hydrocarbon products for which we could be held liable. Furthermore, we collect and store sensitive data in the ordinary course of our business, including personal identification information of our employees as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders. We conduct cyber security audits from time to time and continuously monitor our systems in an effort to mitigate the risk of cyber-attacks or security breaches; however, we do not maintain specialized insurance for possible liability resulting from a cyber-attack on our assets. Despite our security measures, our information systems may become the target of cyber-attacks or security breaches (including employee error, malfeasance or other breaches), which could compromise our network or systems and result in the release or loss of the information stored therein, misappropriation of assets, disruption to our operations or damage to our facilities. As a result of a cyber-attack or security breach, we could also be liable under laws that protect the privacy of personal information, subject to regulatory penalties, experience damage to our reputation or a loss of consumer confidence in our products and services, or incur additional costs for remediation and modification or enhancement of our information systems to prevent future occurrences, all of which could have a material and adverse effect on our business, financial condition or 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 energy and interest rate hedging transactions. These statutory requirements must be implemented through regulations, primarily through the Commodity Futures Trading Commission, or CFTC. To date, the Dodd-Frank Act provisions have not materially changed the way many of our swap transactions are entered into, as we have been able to continue transacting with existing counterparties in over-the-counter markets or with registered exchanges to meet hedging requirements set forth in our risk policies.

The full impact of the Dodd-Frank Act on our hedging activities as an end user is uncertain at this time, as the CFTC continues to promulgate final regulations for position limits. Although the margin rules were recently finalized, the upcoming implementation of key provisions in the margin rules and the finalization of position limit provisions may create new regulatory burdens from these developments in addition to the various business conduct, recordkeeping and reporting rules resulting from the Dodd-Frank Act provisions currently in place. Moreover, longer term, fundamental changes to the swap market as a result of the Dodd-Frank Act requirements could significantly increase the cost of entering into 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.

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

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 facility 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, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues.

We are exposed to restrictions on the ability of Midcoast Operating to repay indebtedness owed to us and MEP and Midcoast Operating to make distributions to us.

We, as financial support provider, entered into a financial support agreement with Midcoast Operating, pursuant to which we will provide letters of credit and guarantees, not to exceed $700 million in the aggregate at any time outstanding, in support of the financial obligations of Midcoast Operating and its wholly owned subsidiaries 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. Our rights to payments under the financial support agreement are subordinated to the rights of the lenders under the private placement debt of MEP and the revolving credit facility of MEP and Midcoast Operating during the continuation of a default under their revolving credit facility. If Midcoast Operating experiences financial or other problems and fails to comply with the covenants under their revolving credit facility, it would limit our ability to receive payment of amounts owed to us under this agreement. In addition, MEP and Midcoast Operating are restricted under their revolving credit facility from making distributions to us in certain circumstances involving certain defaults thereunder or any events of defaults thereunder. Any inability of MEP or Midcoast Operating to make distributions, or of Midcoast Operating to repay its indebtedness to us, could reduce our cash flows and affect our results of operations.

RISKS ARISING FROM OUR PARTNERSHIP STRUCTURE AND RELATIONSHIPS WITH OUR GENERAL PARTNER AND ENBRIDGE MANAGEMENT

The interests of Enbridge may differ from our interests and the interests of our unitholders, and the board of directors of Enbridge Management may consider the interests of all parties to a conflict, not just the interests of our unitholders, in making important business decisions.

Enbridge indirectly owns all of the shares of our General Partner and all of the voting shares of Enbridge Management, and elects all of the directors of both companies. Furthermore, some of the directors and officers of our General Partner and Enbridge Management are also directors and officers of Enbridge. Consequently, conflicts of interest could arise between our unitholders and Enbridge.

Our partnership agreement limits the fiduciary duties of our General Partner to our unitholders. These restrictions allow our General Partner to resolve conflicts of interest by considering the interests of all of the parties to the conflict, including Enbridge Management's interests, our interests and those of our General Partner. In addition, these limitations reduce the rights of our unitholders under our partnership agreement to sue our General Partner or Enbridge Management, its delegate, should its directors or officers act in a way that, were it not for these limitations of liability, would constitute breaches of their fiduciary duties.

We do not have any employees. In managing our business and affairs, we rely on employees of Enbridge, and its affiliates, who act on behalf of and as agents for us. A decrease in the availability of employees from Enbridge could adversely affect us.

Our partnership agreement and the delegation of control agreement limit the fiduciary duties that Enbridge Management and our General Partner owe to our unitholders and restrict the remedies available to our unitholders for actions taken by Enbridge Management and our General Partner that might otherwise constitute a breach of a fiduciary duty.

Our partnership agreement contains provisions that modify the fiduciary duties that our General Partner would otherwise owe to our unitholders under state fiduciary duty law. Through the delegation of control agreement, these modified fiduciary duties also apply to Enbridge Management as the delegate of our General Partner. For example, our partnership agreement:

- permits our General Partner to make a number of decisions, including the determination of which factors it will consider in resolving conflicts of interest, in its "sole discretion." This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;
- provides that any standard of care and duty imposed on our General Partner will be modified, waived or limited as required to permit our General Partner to act under our partnership agreement and to make any decision pursuant to the authority prescribed in our partnership agreement, so long as such action is reasonably believed by the General Partner to be in our best interests; and
- provides that our General Partner and its directors and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions if they acted in good faith.

These and similar provisions in our partnership agreement may restrict the remedies available to our unitholders for actions taken by Enbridge Management or our General Partner that might otherwise constitute a breach of a fiduciary duty.

Potential conflicts of interest may arise among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Because the fiduciary duties of the directors of our General Partner and Enbridge Management have been modified, the directors may be permitted to make decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders.

Conflicts of interest may arise from time to time among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Conflicts of interest may also arise from time to time between us and our unitholders, on the one hand, and Enbridge Management and its shareholders, on the other hand. In managing and controlling us as the delegate of our General Partner, Enbridge Management may consider the interests of all parties to a conflict and may resolve those conflicts by making decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders. The following decisions, among others, could involve conflicts of interest:

- whether we or Enbridge will pursue certain acquisitions or other business opportunities;
- whether we will issue additional units or other equity securities or whether we will purchase outstanding units;
- whether Enbridge Management or Enbridge Partners will issue additional shares or other equity securities;
- the amount of payments to Enbridge and its affiliates for any services rendered for our benefit;
- the amount of costs that are reimbursable to Enbridge Management or Enbridge and its affiliates by us;
- the enforcement of obligations owed to us by Enbridge Management, our General Partner or Enbridge, including obligations regarding competition between Enbridge and us; and
- the retention of separate counsel, accountants or others to perform services for us and Enbridge Management.

In these and similar situations, any decision by Enbridge Management may benefit one group more than another, and in making such decisions, Enbridge Management may consider the interests of all groups, as well as other factors, in deciding whether to take a particular course of action.

In other situations, Enbridge may take certain actions, including engaging in businesses that compete with us or are adverse to us and our unitholders. For example, although Enbridge and its subsidiaries are generally restricted from engaging in any business that is in direct material competition with our businesses, that restriction is subject to the following significant exceptions:

- Enbridge and its subsidiaries are not restricted from continuing to engage in businesses, including the normal development of such businesses, in which they were engaged at the time of our initial public offering in December 1991;
- such restriction is limited geographically only to those routes and products for which we provided transportation at the time of our initial public offering;
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us as part of a larger acquisition, so long as the majority of the value of the business or assets acquired, in Enbridge's reasonable judgment, is not attributable to the competitive business; and
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us if that business is first offered for acquisition to us and the board of directors of Enbridge Management and our unitholders determine not to pursue the acquisition.

Since we were not engaged in any aspect of the natural gas business at the time of our initial public offering, Enbridge and its subsidiaries are not restricted from competing with us in any aspect of the natural gas business. In addition, Enbridge and its subsidiaries would be permitted to transport crude oil and liquid petroleum over routes that are not the same as our Lakehead system, even if such transportation is in direct material competition with our business.

We can issue additional common or other classes of units, including additional i-units to Enbridge Management when it issues additional shares, which would dilute the ownership interest of our unitholders.

The issuance of additional common or other classes of units by us, including the issuance of additional i-units to Enbridge Management when it issues additional shares may have the following effects:

- The amount available for distributions on each unit may decrease;
- The relative voting power of each previously outstanding unit may decrease; and
- The market price of the Class A common units may decline.

Additionally, the public sale by our General Partner of a significant portion of the Class A or Class B common units, Class D units, Class E units or Series 1 preferred units that it or its subsidiary currently owns could reduce the market price of the Class A common units. Our partnership agreement allows the General Partner to cause us to register for public sale any units held by the General Partner or its affiliates. A public or private sale of the Class A or Class B common units, Class D units, Class E units or Series 1 preferred units currently held by our General Partner or its subsidiary could absorb some of the trading market demand for the outstanding Class A common units.

Holders of our limited partner interests have limited voting rights.

Our unitholders have limited voting rights on matters affecting our business, which may have a negative effect on the price at which our common units trade. In particular, the unitholders did not elect our General Partner or the directors of our General Partner or Enbridge Management and have no rights to elect our General Partner or the directors of our General Partner or Enbridge Management on an annual or other continuing basis. Furthermore, if unitholders are not satisfied with the performance of our General Partner, they may find it difficult to remove our General Partner. Under the provisions of our partnership agreement, our General Partner may be removed upon the vote of at least 66.67% of the outstanding common units (excluding the units held by the General Partner and its affiliates) and a majority of the outstanding i-units voting together as a separate class (excluding the number of i-units corresponding to the number of shares of Enbridge Management held by our General Partner and its affiliates). Such removal must, however, provide for the election and succession of a new general partner, who may be required to purchase the departing general partner interest in us in order to become the successor general partner.

Such restrictions may limit the flexibility of the limited partners in removing our general partner, and removal may also result in the general partner interest in us held by the departing general partner being converted into Class A common units.

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. The NYSE does not require us to have, and we do not intend to have, a majority of independent directors on the boards of our General Partner or Enbridge Management, or to establish a compensation committee or nominating and corporate governance committee. In addition, any future issuance of additional Class A common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules that apply to corporations. Accordingly, holders of our Class A common units will not have the same protections afforded to investor owners of certain corporations that are subject to all of the NYSE corporate governance requirements.

We are a holding company and depend entirely on our operating subsidiaries' distributions to service our debt obligations.

We are a holding company with no material operations. If we cannot receive cash distributions from our operating subsidiaries, we will not be able to meet our debt service obligations. Our operating subsidiaries may from time to time incur additional indebtedness under agreements that contain restrictions, which could further limit each operating subsidiaries' ability to make distributions to us.

The debt securities we issue and any guarantees issued by any of our subsidiaries that are guarantors will be structurally subordinated to the claims of the creditors of any of our operating subsidiaries who are not guarantors of the debt securities. Holders of the debt securities will not be creditors of our operating subsidiaries who have not guaranteed the debt securities. The claims to the assets of these non-guarantor operating subsidiaries derive from our own ownership interest in those operating subsidiaries. Claims of our non-guarantor operating subsidiaries' creditors will generally have priority as to the assets of such operating subsidiaries over our own ownership interest claims and will therefore have priority over the holders of our debt, including the debt securities. Our non-guarantor operating subsidiaries' creditors may include:

- general creditors;
- trade creditors;
- secured creditors;
- taxing authorities; and
- creditors holding guarantees.

Enbridge Management's discretion in establishing our cash reserves gives it the ability to reduce the amount of cash available for distribution to our unitholders.

Enbridge Management may establish cash reserves for us that in its reasonable discretion are necessary to fund our future operating and capital expenditures, provide for the proper conduct of business, and comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves affect the amount of cash available for distribution to holders of our common units.

Holders of our Series 1 Preferred Units have a distribution preference, which may adversely affect the value the Class A common units.

The holders of our Series 1 Preferred Units, or Preferred Units, have a preferential right to distributions prior to distributions to the holders of our Class A common units. Through the quarter ending June 30, 2018, the quarterly distributions will not be payable on the Preferred Units and instead will accrue and accumulate. The accrued amounts will be paid in equal amounts over a twelve-quarter period beginning with the first quarter of 2019. Thereafter, the distributions will be paid in cash on a quarterly basis. To the extent that we do not pay in full any distribution on the Preferred Units, the unpaid amount will accrue and accumulate until it is paid in full, and no distributions may be made on the common units during that time.

RISKS ARISING FROM OUR PARTNERSHIP STRUCTURE

Total insurance coverage for multiple insurable incidents exceeding coverage limits would be allocated by our General Partner on an equitable basis.

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates through the policy renewal date of May 1, 2016. The comprehensive insurance program also includes property insurance coverage on our assets, except pipeline assets that are not located at major water crossings, including earnings interruption resulting from an insurable event. 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 Enbridge, MEP, and another Enbridge subsidiary.

RISKS RELATED TO OUR DEBT AND OUR ABILITY TO MAKE DISTRIBUTIONS

***Agreements relating to our debt restrict our ability to make distributions, which could adversely affect the value of our Class A common units, and our ability to incur additional debt and otherwise maintain financial and operating flexibility*.**

MEP is restricted by its credit facility from making distributions to us. MEP and Midcoast Operating are restricted by their revolving credit facility from declaring or making distributions to us if a revolving credit facility payment, insolvency or financial covenant default then exists or any other default then exists which permits the lenders to accelerate the revolving credit facility. However, if no such defaults exist when such distribution is declared, MEP and Midcoast are permitted to make distributions to us even if any such defaults exist when the distribution is made unless MEP or any of its subsidiaries has knowledge that the revolving credit facility has been accelerated.

In addition, we are prohibited from making distributions to our unitholders during (1) the existence of certain defaults under our Credit Facilities or (2) during a period in which we have elected to defer interest payments on the Junior Notes, subject to limited exceptions as set forth in the related indenture. Further, the agreements governing our Credit Facilities may prevent us from engaging in transactions or capitalizing on business opportunities that we believe could be beneficial to us by requiring us to comply with various covenants, including the maintenance of certain financial ratios and restrictions on:

- incurring additional debt;
- entering into mergers or consolidations or sales of assets; and
- granting liens.

Although the indentures governing our senior notes do not limit our ability to incur additional debt, they impose restrictions on our ability to enter into mergers or consolidations and sales of all or substantially all of our assets, to incur liens to secure debt and to enter into sale and leaseback transactions. A breach of any restriction under our Credit Facilities or our indentures could permit the holders of the related debt to declare all amounts outstanding under those agreements immediately due and payable and, in the case of our Credit Facilities, terminate all commitments to extend further credit. Any subsequent refinancing of our current debt or any new indebtedness incurred by us or our subsidiaries could have similar or greater restrictions.

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 our partners 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.

TAX RISKS TO COMMON UNITHOLDERS

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service, or 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.

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.

Section 7704 of the Internal Revenue Code of 1986, or the Internal Revenue Code, provides that publicly-traded partnerships will, as a general rule, be taxed as corporations. An exception exists, however, with respect to a publicly-traded partnership for which 90% or more of the gross income for every taxable year consists of ''qualifying income.'' If less than 90% of our gross income for any taxable year is qualifying income, we will be taxed as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent tax years. Although we do not believe that we will be treated as a corporation for federal income tax purposes based on our current operations, the IRS could disagree with the positions we take. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other tax matter affecting us.

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. For example, we are required to pay Texas franchise tax on our gross income apportioned to Texas.

Imposition of any such taxes may substantially reduce the cash we have available for distribution. 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 a 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 that subjects us to taxation as a corporation for federal income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

The tax treatment of publicly-traded partnerships could be subject to potential legislative, judicial, or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly-traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. 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. It is possible, however, 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 the unitholder. This allocation of taxable income may require the payment of federal income taxes and, in some cases, state and local income taxes, even if the unitholder 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 resulting 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 a unitholder's allocable share of our net taxable income decrease the tax basis of the unitholder's 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 the unitholder sells such common units at a price greater than the unitholder's 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 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. The U.S. Treasury Department issued proposed Treasury 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 Treasury Regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our 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, the unitholder 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, the unitholder 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 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 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 the unitholder's 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 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 currently own assets and conduct business in several 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

Descriptions of our properties and maps depicting the locations of our liquids and 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 liquids systems have pumping stations, tanks, terminals and certain other facilities that are located on land that is owned by us in fee and/or used by us under easements, licenses, leases or permits. Additionally, 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.

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.

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 ''EEP''. The quarterly price ranges per Class A common unit and cash distributions paid per unit for 2015 and 2014 are summarized as follows:

	First	Second	Third	Fourth
2015 Quarters				
High	$ 41.39	$ 38.53	$ 34.49	$ 29.99
Low	$ 35.07	$ 32.93	$ 22.40	$ 19.31
Cash distributions paid	$0.57000	$0.57000	$0.58300	$0.58300
2014 Quarters				
High	$ 29.94	$ 36.95	$ 40.10	$ 41.68
Low	$ 26.30	$ 26.00	$ 31.78	$ 31.63
Cash distributions paid	$0.54350	$0.54350	$0.55500	$0.55500

On February 12, 2016, the last reported sales price of our Class A common units on the NYSE was $15.57. As of January 22, 2016, there were approximately 928 registered holders of record of Class A common units. The holders of record do not include unitholders whose units are held in trust by other entities. There is no established public trading market for our Series 1 Preferred units, Class B common units, Class D units, Class E units or Incentive distribution units, all of which are held directly or indirectly by the General Partner, or our i-units, all of which are held by Enbridge Management.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, the summary historical financial data. 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,				
	2015	2014	2013	2012	2011
	(in millions, except per unit amounts)				
Income Statement Data:					
Operating revenues[9]	$ 5,146.1	$ 7,964.7	$ 7,117.1	$ 6,706.1	$ 9,109.8
Operating expenses[6][7][8][9][10]	4,464.5	6,878.0	6,676.7	5,812.9	8,113.0
Operating income	681.6	1,086.7	440.4	893.2	996.8
Interest expense	(322.0)	(403.2)	(320.4)	(345.0)	(320.6)
Allowance for equity used during construction[11]	70.3	57.2	43.1	11.2	—
Other income (expense)	29.3	8.9	16.0	(1.2)	6.5
Income tax benefit (expense)	(4.9)	(9.6)	(18.7)	(8.1)	(5.5)
Net income	454.3	740.0	160.4	550.1	677.2
Less: Noncontrolling interest	221.1	263.3	88.3	57.0	53.2
Series 1 preferred unit distributions	90.0	90.0	58.2	—	—
Accretion of discount on Series 1 preferred units	11.2	14.9	9.2	—	—
Income (loss) from continuing operations attributable to general and limited partnership interests	$ 132.0	$ 371.8	$ 4.7	$ 493.1	$ 624.0
Net income (loss) allocable to common units and i-units	$ (84.8)	$ 218.4	$ (122.7)	$ 369.2	$ 520.5
Net income (loss) per common unit and i-unit (basic and diluted)[1]	$ (0.25)	$ 0.67	$ (0.39)	$ 1.27	$ 1.99
Cash distributions paid per limited partner unit outstanding	$ 2.3060	$ 2.1970	$ 2.1740	$ 2.1520	$ 2.0925
Financial Position Data (at year end):					
Property, plant and equipment, net	$17,412.4	$15,692.7	$13,176.8	$10,937.6	$ 9,439.4
Total assets	18,815.8	17,746.9	14,901.5	12,796.8	11,370.1
Long-term debt, excluding current maturities[3]	7,769.9	6,675.2	4,777.4	5,501.7	4,816.1
Notes payable to General Partner	—	306.0	318.0	330.0	342.0
Partners' capital:					
Series 1 preferred units[12]	1,186.8	1,175.6	1,160.7	—	—
Class D units[13]	2,517.6	2,516.8	—	—	—
Class E units[14]	778.2	—	—	—	—
Class A common units[4]	—	235.5	2,979.0	3,590.2	3,386.7
Class B common units	—	—	65.3	83.9	82.2
i-units[5][8]	212.6	712.6	1,291.9	801.8	728.6
Incentive distribution units[15]	495.0	493.0	—	—	—
General Partner	147.4	198.3	301.5	299.0	285.6
Accumulated other comprehensive deficit	(370.0)	(211.4)	(76.6)	(320.5)	(316.5)
Noncontrolling interest	3,944.5	3,609.0	1,975.6	793.5	445.5
Partners' capital	$ 8,912.1	$ 8,729.4	$ 7,697.4	$ 5,247.9	$ 4,612.1
Cash Flow Data:					
Cash flows provided by operating activities[6][7][8][9][10]	$ 1,030.8	$ 816.8	$ 1,212.4	$ 851.0	$ 1,045.6
Cash flows used in investing activities	$ 2,126.4	$ 2,976.6	$ 2,642.9	$ 1,906.6	$ 1,099.0
Cash flows provided by financing activities[3][4][5]	$ 1,045.8	$ 2,192.9	$ 1,367.4	$ 860.6	$ 331.4
Additions to property, plant and equipment, and acquisitions included in investing activities, net of cash acquired[2]	$ 2,201.8	$ 2,933.8	$ 2,410.8	$ 1,739.9	$ 1,091.8

(1) The allocation of net income (loss) to the General Partner in the following amounts has been deducted before calculating income (loss) from continuing operations per common unit and i-unit: 2015, $234.7 million; 2014, $163.9 million; 2013, $144.1 million; 2012, $129.3 million; and 2011, $104.5 million.

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

Date of Acquisition	Description of Acquisition
February 2015	Acquisition of the midstream business of New Gulf Resources, LLC, or NGR, in Texas.

(3) Our financial position and cash flow data include the effect of the following debt issuances and debt repayments:

Date of Debt Issuance	Debt Type	Amount of Debt Issuance
October 2015	4.375% Senior Notes	$500
October 2015	5.875% Senior Notes	$500
October 2015	7.375% Senior Notes	$600
September 2014	3.560% MEP Senior Notes	$ 75
September 2014	4.040% MEP Senior Notes	$175
September 2014	4.420% MEP Senior Notes	$150
September 2011	4.200% Senior Notes	$600
September 2011	5.500% Senior Notes	$150

- For the year ended December 31, 2015 there were no debt repayments.
- For the year ended December 31, 2014 we repaid $200.0 million of our 5.350% senior notes.
- For the year ended December 31, 2013 we repaid $200.0 million of our 4.750% senior notes.
- For the year ended December 31, 2012 we repaid $100.0 million of our 7.900% senior notes.
- For the year ended December 31, 2011 we repaid $31.0 million of our First Mortgage Notes.

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

Date of Unit Issuance	Class of Limited Partnership Interest	Number of Units Issued	Net Proceeds Including General Partner Contribution
March 2015	Class A	8,000,000	$294.8
September 2012	Class A	16,100,000	$456.2
May 2012	Class A	64,464	$ 2.0
2011 Equity Distribution Agreement issuances	Class A	3,084,208	$ 95.5
December 2011	Class A	9,775,000	$298.1
September 2011	Class A	8,000,000	$222.9
July 2011	Class A	8,050,000	$238.6
January 2011	Class A	50,650	$ 1.6

- All unit issuances prior to the April 2011 stock split have been retrospectively adjusted to be comparable.
- In January 2011 and May 2012 we issued Class A common units in connection with land acquisitions.

(5) Our financial position and cash flow data include the effect of the following distributions:

Fiscal Year	Amount of Distribution of i-units to i-unit Holders[a]	Retained from General Partner	Distribution of Cash
2015	$161.2	$3.3	$835.9
2014	$143.9	$3.0	$727.8
2013	$113.8	$2.3	$708.9
2012	$ 85.0	$1.7	$660.3
2011	$ 75.7	$1.5	$565.7

(a) The quarterly in-kind distributions of 5 million, 4.6 million, 3.8 million, 2.6 million and 2.4 million i-units during 2015, 2014, 2013, 2012, 2011, respectively were made to Enbridge Management in lieu of cash distributions.

(6) Operating results for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, were affected by costs incurred in connection with the crude oil releases on Lines 6A and 6B of our Lakehead system. In connection with these incidents for the years ended December 31, 2014, 2013, 2012 and 2011, we accrued costs of $85.9 million, $302.0 million, $55.0 million and $218.0 million, respectively, for emergency response, environmental remediation and cleanup activities associated with the crude oil releases, before insurance recoveries and excluding fines and penalties. For the year ended December 31, 2015, there were no costs accrued in connection with the aforementioned incidents. In addition, for the years ended December 31, 2013, 2012 and 2011, we recognized $42.0 million, $170.0 million and $335.0 million, respectively, in insurance recoveries related to such incidents. For the years ended December 31, 2015 and 2014, there were no insurance recoveries recognized for the aforementioned incidents. Based on our current estimate of costs associated with these crude oil releases through December 31, 2015, Enbridge and its affiliates, including us, have exceeded the limits of coverage under this insurance policy; however we are in litigation to recover the remaining $103.0 million balance of our aggregate insurance coverage, but there can be no assurance that we will collect the remaining insurance balance.

(7) Operating results for the year ended December 31, 2011 were affected by $52.2 million we received in the second quarter of 2011 for the settlement of a dispute related to oil measurement losses, which we recognized as a reduction to operating expenses.

(8) Operating results for the year ended December 31, 2011 were affected by $18.0 million of additional expense we recognized in the fourth quarter of 2011, related to accounting misstatements and accounting errors. At our wholly-owned trucking and NGL marketing subsidiary, we identified accounting misstatements and other errors in early 2012 associated with the financial statement recognition of NGL product purchases and sales within our Natural Gas segment over a period from at least 2005 through 2011 prior to their detection in 2012.

[9] Operating results for the year ended December 31, 2012 were affected by $8.9 million of estimated costs accrued in connection with the July 27, 2012 crude oil release on Line 14 of our Lakehead system as discussed in Item 8. *Financial Statements and Supplementary Data,* Note 13. *Commitments and Contingencies*. The $10.5 million accrual is inclusive of approximately $1.6 million of lost revenue and excludes any potential fines or penalties. We will be pursuing claims under our insurance policy, although we do not expect any recoveries to be significant.

[10] Operating results for the year ended December 31, 2015 were affected by a $246.7 million goodwill impairment charge recognized during the second quarter of 2015, as discussed in Item 8. *Financial Statements and Supplementary Data,* Note 8. *Goodwill*. During May 2015, due to adverse market conditions facing our business, we learned from producers that reductions in drilling would be sustained and prolonged due to continued low prices for natural gas and NGLs. As a result, we determined that the impact on our forecasted operating profits and cash flows for our Natural Gas segment for the next five years would be significantly reduced from our prior forecasts.

[11] Since October 2011, we and Enbridge have announced multiple expansion projects that have or will provide increased access to refineries in the U. S. Upper Midwest and in Canada in the provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. These projects collectively referred to as the Eastern Access Projects and Mainline Expansion Projects, will cost approximately $2.7 billion and $2.4 billion, respectively. These projects have been undertaken on a cost-of-service basis and are funded 75% by our General Partner and 25% by the Partnership under the Eastern Access Joint Funding Agreement and Mainline Expansion Joint Funding Agreement, as amended. In conjunction with our application of the provisions of regulatory accounting, we recorded allowance for equity during construction, or AEDC, of $60.0 million, $54.7 million and $33.3 million, for the years ended December 31, 2015 and 2014, and 2013 and respectively, which is recorded in ''Allowance for equity used during construction'' in our consolidated statements of income.

[12] On May 8, 2013, we issued a total of 48.0 million Series 1 preferred units. The Series 1 preferred units are entitled to cash distributions of 7.50% of the issue price, payable quarterly, and are convertible into Class A common units on or after June 1, 2018, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the quarterly distributions deferred for the first full twenty quarters ending June 30, 2018, as adjusted for splits, combinations and unit distributions.

[13] On July 1, 2014, we issued a total of 66.1 million Class D units, which are owned by a subsidiary of the General Partner. The Class D units carry a distribution equal to the quarterly distribution on the Class A common units. The Class D units are convertible on a one-for-one basis into Class A common units at any time after the fifth anniversary of the closing date, at the holder's option.

[14] On January 2, 2015, we issued a total of approximately 18.1 million Class E units, which are owned by a subsidiary of the General Partner. Class E units are entitled to the same distributions as Class A common units held by the public and are convertible into Class A common units on a one-for-one basis at the General Partner's option. The Class E units are redeemable at our option after 30 years, if not earlier converted by the General Partner.

[15] On July 1, 2014, we issued a total of 1,000 Incentive distribution units, or IDUs, which are owned by a wholly-owned subsidiary of the General Partner. The IDUs are entitled to receive 23% of the incremental distributions we pay in excess of the $0.5435 per common unit and Class D unit per quarter.

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 included in Item 8. *Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

RESULTS OF OPERATIONS — OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum; and
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities, along with supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through two business segments: Liquids and Natural Gas. Our Liquids segment includes the operations of our Lakehead, Mid-Continent and North Dakota systems. These systems largely consist of Federal Energy Regulatory Commission, or FERC, regulated interstate crude oil and liquid petroleum pipelines, gathering systems and storage facilities. The Lakehead system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. Our Liquids systems generate revenues primarily from charging shippers a rate per barrel to gather, transport and store crude oil and liquid petroleum.

Our Natural Gas segment includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities, condensate stabilizers and an NGL fractionation facility. Moreover, our Natural Gas segment also provides supply, transmission, storage and sales services to producers and wholesale customers on our natural gas gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Revenues for our Natural Gas segment 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. Additionally, we provide other services that are valued by our customers. Segment gross margin is derived from the compensation we receive from customers in the form of fees or commodities we receive for providing services in addition to the proceeds we receive for sales of natural gas, NGLs and condensate to affiliates and third-parties.

The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31, 2015, 2014 and 2013:

	December 31,		
	2015	2014	2013
		(in millions)	
Operating income (loss)			
Liquids	$ 994.0	$ 938.9	$ 392.6
Natural Gas	(298.0)	158.4	55.4
Corporate, operating and administrative	(14.4)	(10.6)	(7.6)
Total operating income	681.6	1,086.7	440.4
Interest expense	(322.0)	(403.2)	(320.4)
Allowance for equity used during construction	70.3	57.2	43.1
Other income	29.3	8.9	16.0
Income tax expense	(4.9)	(9.6)	(18.7)
Net income	454.3	740.0	160.4
Less: Net income attributable to:			
Noncontrolling interest	221.1	263.3	88.3
Series 1 preferred unit distributions	90.0	90.0	58.2
Accretion of discount on Series 1 preferred units	11.2	14.9	9.2
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 132.0	$ 371.8	$ 4.7

Highlights

Liquids

Our Liquids segment operating income increased $55.1 million for the year ended December 31, 2015, as compared with the same period in 2014, primarily due to additional assets placed in service and an increase in volumes on our systems. In 2014 and 2015, $2.7 billion and $1.6 billion of additional assets, respectively, were placed into service on our Lakehead system, including portions of the Eastern Access, Mainline Expansion projects and other projects. Average daily volumes delivered on our liquids systems increased 249,000 Bpd, or 9.46%, for the year ended December 31, 2015, when compared with the same period in 2014, due to increased capacity. Lastly, the Liquids segment operating income increased as a result of reduced environmental costs, net of recoveries, primarily due to lower environmental accruals, net of recoveries, related to the Line 6B crude oil release.

Natural Gas

Our Natural Gas segment operating income decreased $456.4 million for the year ended December 31, 2015, as compared to the same period in 2014, primarily as a result of a non-cash goodwill impairment charge of $246.7 million that was recorded during the second quarter of 2015. In addition, segment gross margin experienced a net decrease of $216.8 million, due to non-cash, mark-to-market losses of $58.3 million for the year ended December 31, 2015, as compared to gains of $158.5 million for year ended December 31, 2014. Furthermore, there were declines in natural gas pricing differentials and production volumes for the year ended December 31, 2015, when compared to the same period in 2014, primarily due to the current low commodity pricing environment. We expect that the lower commodity price trends will continue through 2016. These decreases in segment gross margin were offset by over $70.0 million of workforce and other cost reductions for the year ended December 31, 2015.

Derivative Transactions and Hedging Activities

Contractual arrangements in our Liquids, Natural Gas, and Corporate segments expose us to market risks associated with changes in (1) commodity prices where we receive crude oil, natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs and (2) interest rates on our variable rate debt. Our unhedged commodity position is fully exposed to fluctuations in commodity prices, which can be significant during periods of price volatility. We use derivative financial instruments such as futures, forwards, swaps, options and other financial instruments with similar characteristics, to manage the risks associated with market fluctuations in commodity prices and interest rates, 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 or interest rates. Derivative financial instruments that do not receive hedge accounting under the provisions of authoritative accounting guidance 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.

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 receive hedge accounting in our consolidated statements of income as follows:

- Liquids segment commodity-based derivatives — ‘‘Transportation and other services’’ and ‘‘Power’’
- Natural Gas segment commodity-based derivatives — ‘‘Commodity sales’’ and ‘‘Commodity costs’’
- Corporate interest rate derivatives — ‘‘Interest expense’’

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,		
	2015	2014	2013
		(in millions)	
Liquids segment:			
Non-qualified hedges	$(15.5)	$ 13.6	$ (3.9)
Natural Gas segment:			
Hedge ineffectiveness	(4.1)	5.6	3.3
Non-qualified hedges	(54.2)	152.9	(6.3)
Commodity derivative fair value net gains (losses)	(73.8)	172.1	(6.9)
Corporate:			
Interest rate hedge ineffectiveness	98.9	(100.1)	(21.5)
Non-qualified interest rate hedges	—	—	(0.2)
Derivative fair value net gains (losses)	$ 25.1	$ 72.0	$(28.6)

RESULTS OF OPERATIONS — BY SEGMENT

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. We provide a detailed description of each of these systems in Item 1. *Business*. The following table sets forth the operating results and statistics of our Liquids segment assets for the periods presented:

	December 31,		
	2015	2014	2013
		(in millions)	
Operating Results:			
Operating revenue	$2,303.4	$2,070.4	$1,519.9
Operating expenses:			
Environmental costs, net of recoveries	3.1	97.3	273.7
Operating and administrative	605.9	500.8	461.0
Power	259.5	226.6	147.7
Asset Impairment	62.5	—	—
Depreciation and amortization	378.4	306.8	244.9
Total operating expenses	1,309.4	1,131.5	1,127.3
Operating income	$ 994.0	$ 938.9	$ 392.6
Operating Statistics			
Lakehead system:			
United States[(1)]	1,869	1,669	1,427
Province of Ontario[(1)]	446	444	389
Total Lakehead system delivery volumes[(1)]	2,315	2,113	1,816
Barrel miles (billions)	640	582	487
Average haul (miles)	757	755	735
Mid-Continent system delivery volumes[(1)]	212	200	201
North Dakota system:			
Trunkline[(1)]	351	315	168
Gathering[(1)]	2	3	3
Total North Dakota system delivery volumes[(1)]	353	318	171
Total Liquids segment delivery volumes[(1)]	2,880	2,631	2,188

(1) Average barrels per day in thousands.

Year ended December 31, 2015 compared with year ended December 31, 2014

Operating income of our Liquids segment for the year ended December 31, 2015, increased $55.1 million, as compared with the same period in 2014, primarily due to the reasons discussed below.

Operating revenue increased $233.0 million for the year ended December 31, 2015, when compared with the same period in 2014, primarily due to the following reasons. Operating revenue increased $25.2 million, primarily due to higher average rates. Operating revenue also increased $223.8 million from increased surcharge revenue for projects on our Lakehead system subject to regulatory accounting, primarily as a result of placing $2.7 billion and $1.6 billion of assets into service on the Lakehead system in 2014 and 2015, respectively. These additional assets placed into service included components of the Eastern Access, Mainline Expansion Projects and other expansion projects. This amount was partially offset by a $101.4 million decrease in rates due to greater qualifying volume credits related to Lakehead toll revenues. Qualifying volume credits represent a contractual obligation, which were introduced with the original Southern Access and Alberta Clipper expansions, to return a portion of revenue to our shippers when volumes shipped exceed certain predetermined levels. Once these predetermined levels are exceeded, the expansion projects are earning their full cost-of-service. Hence, to limit project earnings to agreed levels, the credits are returned to the shippers through the tolls.

Operating revenue also increased $87.0 million due to increased average daily delivery volumes. Volumes delivered increased 249,000 Bpd, of which 202,000 Bpd and $72.3 million were attributable to higher volumes on our Lakehead system as a result of additional system capacity from the aforementioned assets that were placed into service. The North Dakota system experienced an increase of 35,000 Bpd and $12.7 million in revenues due to our system's enhanced market access in addition to volumes shifting onto this system and away from higher cost alternatives such as transportation by rail. Additionally, our operating revenue also increased by $25.0 million due to a surcharge that went into effect on April 1, 2015, which is designed to recover half of the costs of a hydrostatic test on Line 2B.

Increases to operating revenue were also partially offset by decreased non-cash, mark-to-market net gains of $28.4 million related to derivative financial instruments. The decrease is primarily the result of a $19.4 million reclassification of previously recognized unrealized mark-to-market net gains where the underlying transactions were settled, coupled with $9.0 million of decreased non-cash, mark-to-market net gains due to smaller decreases in average forward prices during 2015 than during 2014.

Environmental costs, net of recoveries, decreased $94.2 million for the year ended December 31, 2015 when compared with the same period in 2014. This decrease is primarily related to cost accruals for the Line 6B crude oil release. During the year ended December 31, 2015, there were no cost accruals for the Line 6B crude oil release. For the same period ended 2014, there were $85.9 million of cost accruals.

Operating and administrative expenses increased $105.1 million for the year ended December 31, 2015, when compared with the same period in 2014, primarily due to $64.2 million of pipeline integrity costs. The increase in pipeline integrity costs is primarily due to $79.1 million of costs in 2015 for the hydrostatic test on Line 2B. Pipeline integrity costs were partially offset by a $14.9 million decrease in other integrity costs.

Additionally, the increase in operating and administrative expenses was also due to cost increases of $18.9 million of property taxes, $15.3 million of workforce related costs and $6.8 million of other operating and administrative expenses, mainly consisting of contract labor, insurance, rents and lease payments, and professional and regulatory services. These cost increases primarily result from the additional assets placed into service during 2014 and 2015.

Power costs increased $32.9 million for the year ended December 31, 2015 when compared with the year ended 2014, primarily as a result of increased volumes on our systems.

During the year ended December 31, 2015, we recorded a non-cash impairment loss of $62.5 million to write off the remaining carrying value of our Berthold rail facility due to contracts that have not been renewed subsequent to 2016. There were no such asset impairment charges for the year ended December 31, 2014.

The increase in depreciation expense of $71.6 million for the year ended December 31, 2015, when compared with the same period in 2014, is directly attributable to additional assets placed into service, primarily on projects discussed above.

Year ended December 31, 2014 compared with year ended December 31, 2013

Operating revenue of our Liquids segment increased $550.5 million for the year ended December 31, 2014, when compared with the same period in 2013, primarily due to the filing of tariffs to increase the rates for our Lakehead, North Dakota and Ozark systems with the FERC. These rate increases became effective on April 1 and July 1, 2014, for our North Dakota and Ozark systems, and August 1, 2014, for our Lakehead system. The increase in rates accounted for $339.5 million of the increase in operating revenue for the year ended December 31, 2014, when compared to December 31, 2013. The large increase in rates is primarily due to $2.7 billion of additional assets placed into service in 2014 on the Lakehead system, including the Eastern Access, Mainline Expansion and other expansion projects. Additionally, 2014 revenues increased from a full year of revenue for Lakehead and North Dakota expansion projects placed into service during 2013. The rate increases effective April 1, 2014, primarily resulted from annual tariff filings for our North Dakota and Ozark systems to reflect our projected costs and throughput for 2014 and adjustments for the prior year. The rate increases effective July 1, 2014, resulted from an annual index rate filing to adjust base rates for our North Dakota and Ozark systems in compliance with rate ceilings allowed by the FERC. The rate increases effective August 1, 2014, resulted from tariff filings for our Lakehead system to reflect our projected costs and throughput for 2014, adjustments for the prior year, and an indexing adjustment to base rates in compliance with the indexed rate ceilings allowed by the FERC. Historically, the Lakehead system's annual tariff filing has been effective April 1 and its annual index rate filing has been effective July 1; however, the filings were delayed due to negotiations with CAPP concerning certain components of the tariff rate structure.

Operating revenue also increased for the year ended December 31, 2014, when compared to the same period in 2013, by $139.9 million due to increased average daily delivery volumes on our Lakehead and North Dakota systems. Average daily volumes delivered on our liquids systems increased 443,000 Bpd for the year ended December 31, 2014, compared to the year ended December 31, 2013. Of that amount, our Lakehead system realized higher daily volumes of 297,000 Bpd, which contributed to increased revenue of $75.7 million. This increase in volumes is attributable to a combination of increased supply from Western Canada and additional capacity on our system from the assets placed into service in 2014 as discussed above. The North Dakota system also experienced an increase of 147,000 Bpd primarily due to narrowing market pricing differentials from North Dakota to major market centers. This reduction in pricing differentials shifted volumes onto our North Dakota system and away from rail competitors.

Additionally, operating revenue increased during the year ended December 31, 2014, when compared to the same period in 2013, due to an increase of $17.6 million primarily from our Berthold Rail System that was placed into service in March 2013.

Operating revenue increased for the year ended December 31, 2014, when compared with the same period in 2013, due to an increase of $24.2 million in ship-or-pay contracts on our North Dakota and Bakken systems. This is primarily due to increased committed volumes for certain shippers.

Additionally, operating revenue increased as a result of increases of $17.3 million of non-cash, mark-to-market net gains related to derivative financial instruments. The increase is the result of $2.3 million in realized gains related to our settled derivative financial instruments, coupled with $15.0 million of non-cash, mark-to-market net gains due to decreases in average forward prices of crude oil during 2014, compared to increases in the average forward prices of crude oil during 2013.

Environmental costs, net of recoveries, decreased $176.4 million for the year ended December 31, 2014, when compared with the same period in 2013, primarily due to lower environmental accruals, net of recoveries, related to the Line 6B crude oil release. During the year ended December 31, 2014, we recognized $85.9 million in cost accruals compared to $302.0 million for the comparable period ended December 31, 2013. There were no insurance recoveries during 2014 compared to $42.0 million during 2013.

Operating and administrative expenses increased $39.8 million for the year ended December 31, 2014, when compared with the same period in 2013, primarily due to: $40.4 million of workforce related costs; $18.6 million of property taxes; and $34.3 million of other operating and administrative expenses, mainly consisting of contract labor, insurance, rents and lease payments, and professional and regulatory services. These cost increases primarily result from the additional assets placed into service during 2014. The increase in operating and administrative expenses is offset by a decrease of $53.9 million of pipeline integrity costs primarily due to $57.7 million of costs incurred for a hydrostatic test we performed on Line 14 during 2013 that did not occur again during 2014.

Power costs increased $78.9 million for the year ended December 31, 2014, when compared to the year ended December 31, 2013, primarily as a result of increased volumes on our systems.

The increase in depreciation expense of $61.9 million for the year ended December 31, 2014, is directly attributable to additional assets placed into service, primarily on projects discussed above. The increase in depreciation expense was offset by a $12.6 million reduction due to depreciation studies we completed during the fourth quarter of 2013 for our North Dakota and Ozark systems. The depreciation studies extended the asset lives due to additional reserve growth and pipeline connectivity needs, and the total impact of these studies is a reduction of annual depreciation expense of $16.8 million on a prospective basis.

Future Prospects Update for Liquids

We currently have a multi-billion dollar growth program underway, with projects coming into service through early 2019, in addition to options to increase our economic interest in projects that are jointly funded by us and Enbridge. Furthermore, Enbridge has a large inventory of United States liquids pipelines assets and continues to evaluate selective drop down opportunities of approximately $500 million annually, subject to market conditions and our financing capacity.

Impact of Commodity Price Declines

Volatility in commodity prices can impact production volumes in the oil sands region of Western Canada and the Bakken region of North Dakota, our two primary crude oil supply basins.

The relatively high costs and large up-front capital investments required by oil sands projects involves significant assumptions around short-term and long-term crude oil fundamentals, including world supply and demand, North American supply and demand, and price outlook, among many other factors. As oil sands production is long-term in nature, the long-term outlook is significant to a producer's investment decision. In the near-term, the current pricing environment is not expected to materially impact projected growth from the oil sands region.

We expect that the current crude oil price downturn may result in deferral of some oil sands projects, particularly if the current pricing environment continues throughout 2016. However, we expect that projects already under construction will be finished and enter production. In addition, current production volumes from the oil sands are unlikely to decrease absent an operational upset at one of the oil sands operations. Accordingly, we do not anticipate significant changes in our short-term crude oil volume outlook from the oil sands. Our long-term growth in volumes and additional infrastructure expansion will depend on long-term fundamentals. During this period of uncertainty, we believe our pipeline systems are ideally positioned to capture incremental pipeline capacity needs with lower cost, smaller scale expansions of our large Lakehead, North Dakota and Mid-Continent pipeline systems.

Tight sands oil production in any basin in North America will be comparatively more sensitive to the short-term changes in commodity prices due to the production profile associated with tight sands oil wells. Accordingly, we expect a reduction in the growth rate for North American tight sands and shale oil. We believe that rail will be the source of transportation most directly impacted by any declines in production due to its comparatively higher cost relative to pipeline transportation.

Financial impacts to our pipeline systems, in the event the rate of growth were to slow or volumes were to decline, is partially offset by our cost-of-service agreements, toll structures and existing demand to transport crude oil from existing production. We do not believe that the decline in crude oil prices will impact our liquids segment meaningfully in the short-term. However, a long-term decline in crude oil prices could have a more significant impact on future production and our rate of growth.

Expansion Projects

The table and discussion below summarizes our commercially secured projects for the Liquids segment that have been recently placed into service or will be placed into service in future periods:

Projects	Total Estimated Capital Costs	In-Service Date	Funding
	(in millions)		
Line 3 Replacement Program[(1)]	$2,600	Early 2019	EEP[(2)]
Sandpiper Project[(1)]	2,600	Early 2019	Joint[(3)]
Eastern Access Projects:			
Eastern Access Upsize – Line 6B Expansion	310	Mid-2016	Joint[(4)]
U.S. Mainline Expansions:			
Chicago Area Connectivity (Line 78)	540	Fourth quarter 2015	Joint[(5)]
Line 61 (800,000 Bpd capacity)	395	Second quarter 2015	Joint[(5)]
Line 61 (Additional tankage)	380	Third quarter 2015 – Third quarter 2016	Joint[(5)]
Line 61 (1,200,000 Bpd capacity)[(6)]	485	Early 2019	Joint[(5)]
Line 67	240	Third quarter 2015	Joint[(5)]

(1) Estimated in-service dates and capital costs are pending regulatory and other approvals.

(2) A special committee of independent directors of the Board of Enbridge Management has been established to consider a joint funding agreement with Enbridge.

(3) Jointly funded 62.5% by us and 37.5% by Williston Basin Pipeline LLC, an affiliate of Marathon Petroleum Corp., under the North Dakota Pipeline Company Amended and Restated Limited Liability Company Agreement. Estimated capital costs are presented at 100% before Williston's contributions.

(4) Jointly funded 25% by the Partnership and 75% by our General Partner under Eastern Access Joint Funding Agreement. Estimated capital costs are presented at 100% before our General Partner's contributions.

(5) Jointly funded 25% by the Partnership and 75% by our General Partner under Mainline Expansion Joint Funding Agreement. Estimated capital costs are presented at 100% before our General Partner's contributions.

(6) Estimated in-service date will be adjusted to coincide with the in-service date of the Sandpiper Project and the impact of cost to be reviewed.

Line 3 Replacement Program

On March 3, 2014, we and Enbridge announced that shipper support was received to replace portions of the existing 1,031-mile Line 3 pipeline on the Canadian Mainline/Lakehead system between Hardisty, Alberta, Canada and Superior, Wisconsin. Our portion of the Line 3 Replacement Program, referred to as the US L3R Program, includes replacing 358 miles from the U.S./Canadian border at Neche, North Dakota to Superior, Wisconsin. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow us and Enbridge to optimize throughput on the mainline system from Western Canada into Superior, Wisconsin.

We are in the process of obtaining the appropriate permits for constructing the US L3R Program in Minnesota. The project requires both a Certificate of Need, or Certificate, and an approval of the pipeline's route, or Route Permit, from the Minnesota Public Utilities Commission, or MNPUC. The MNPUC found both the Certificate and Route Permit applications for the US L3R Program through Minnesota to be complete. The MNPUC had sent the Certificate application to the Administrative Law Judge, or ALJ, for a pre-hearing meeting to establish a schedule. With respect to the Route Permit, the Minnesota Department of Commerce held public scoping meetings in August 2015. As a result of the Minnesota Court of Appeals decision for the Sandpiper Project, the ALJ requested direction on how to proceed with the Certificate process for Line 3. On February 1, 2016, the MNPUC issued a written order, or the US L3R Order, joining the Line 3 Certificate and Route Permit dockets and requiring the Department of Commerce to prepare an Environmental Impact Statement, or EIS, before the Certificate and Route Permit processes commence, and sent the cases to the Office of Administrative Hearings, or OAH, with direction to restart the process. We believe that the directions from the MNPUC in most of the decisions set out in the US L3R Order were consistent with expectations and provide clarity on process matters; however, we believe the requirement to have a final EIS prior to beginning the Certificate and Route Permit processes is unprecedented and contrary to Minnesota law. On February 5, 2016, we filed a Petition for Reconsideration of this aspect of the US L3R Order. If upheld, the US L3R Order will result in delays in the processing of the applications and an increase in the costs of the project.

Subject to regulatory and other approvals, the US L3R Program is now expected to be completed in early 2019. We continue to review the impact of this order on the US L3R Program's schedule and cost estimates. A special committee of independent directors of the board of Enbridge Management has been established to consider a proposal from our General Partner, on behalf of Enbridge, that would establish joint funding arrangements for the US L3R Program by creating an additional jointly owned series of partnership interests in Enbridge Energy, Limited Partnership, or OLP, similar to the series established for Eastern Access and Mainline Expansion.

We will recover our costs based on our existing Facilities Surcharge Mechanism, or FSM, with the initial term being 15 years. For purposes of the toll surcharge, the agreement specifies a 30 year recovery of the capital based on a cost-of-service methodology.

Light Oil Market Access Program

We and Enbridge have invested in a Light Oil Market Access Program to expand access to markets for growing volumes of light oil production. This program responds to significant recent developments with respect to supply of light oil from U.S. north central formations and western Canada, as well as refinery demand for light oil in the U.S. Midwest and eastern Canada. The Light Oil Market Access Program includes several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Project, enhance Enbridge's Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries.

Sandpiper Project

Included in the Light Oil Market Access Program is the Sandpiper Project which will expand and extend the North Dakota feeder system by 225,000 Bpd to a total of 580,000 Bpd. The proposed expansion will involve construction of an approximate 600-mile pipeline from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 250,000 Bpd of capacity on the twin line between Tioga and Berthold, North Dakota and 225,000 Bpd of capacity on the twin line between Berthold and Clearbrook both with a new 24-inch diameter pipeline, in addition to adding 375,000 Bpd between Clearbrook and Superior with a new 30-inch diameter pipeline.

We are in the process of obtaining the appropriate permits for the construction of the Sandpiper Project in Minnesota. The project requires both a Certificate and Route Permit from the MNPUC. On August 3, 2015, the MNPUC issued an order granting a Certificate and a separate order restarting the Route Permit proceedings. On September 14, 2015, the Minnesota Court of Appeals reversed the MNPUC's Certificate order stating that an EIS must be prepared prior to reaching a final decision in cases where proceedings have been separated and handled sequentially. On January 11, 2016, the MNPUC issued a written order, or the Sandpiper Order, rejoining the Certificate and Route Permit process, requiring the Department of Commerce to commence preparation of an EIS, ordering the OAH to recommence processing the Certificate and Route Permit applications but to take judicial notice of the record already developed for the Certificate, and requiring that a final EIS be issued before the Certificate and Route Permit processes commence. We believe that the directions from the MNPUC in most of the decisions set out in the Sandpiper Order were consistent with expectations and provide clarity on process matters; however, we believe the requirement to have a final EIS prior to beginning the Certificate and Route Permit processes is unprecedented and contrary to Minnesota law. On February 1, 2016, we filed a Petition for Reconsideration for this aspect of the Sandpiper Order. If upheld, the Sandpiper Order will result in delays in processing of the applications and an increase in the cost of the project. Subject to regulatory and other approvals, we estimate that the in-service date for the Sandpiper Project will occur in early 2019. We continue to review the impact of the Sandpiper Order on the project's schedule and cost estimates.

Marathon Petroleum Corporation, or MPC, has been secured as an anchor shipper for the Sandpiper Project. As part of the arrangement, we, through our subsidiary, North Dakota Pipeline Company LLC, or NDPC, and Williston Basin Pipeline LLC, or Williston, an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of the Sandpiper Project construction and have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed $1.2 billion in aggregate. In return for funding part of Sandpiper's construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper.

Eastern Access Projects

Since October 2011, we and Enbridge have announced multiple expansion projects that will provide increased access to refineries in the U.S. Upper Midwest and the Canadian provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. As part of the Light Oil Market Access Program announced in 2012, we announced a further expansion project of Line 6B to increase capacity from 500,000 Bpd to 570,000 Bpd and to include: pump station modifications at Griffith, Niles and Mendon, Indiana; additional modifications at the Griffith and Stockbridge, Michigan terminals; and breakout tankage at Stockbridge. The expected cost of this expansion is approximately $310 million and is expected to be placed into service in mid-2016. This project is being funded 75% by our General Partner and 25% by us under the Eastern Access Joint Funding Agreement. Within one year of the in-service date, we will have the option to increase our economic interest by up to 15% at cost. The Eastern Access Projects, which includes the Line 6B Expansion project along with the previously completed Line 5 Expansion, Line 62 Expansion and the Line 6B Replacement projects, will cost approximately $2.7 billion.

U.S. Mainline Expansions

In 2012 and 2013, we announced further expansion projects for our mainline pipeline system including: (1) expanding our existing 36-inch diameter Alberta Clipper pipeline, or Line 67; (2) expanding our existing 42-inch diameter Southern Access pipeline, or Line 61; and (3) expanding by constructing Line 78, a twin of Line 62.

The current scope of the Line 67 pipeline expansion between Neche, North Dakota and the Superior, Wisconsin Terminal consists of two phases. The initial phase increased capacity from 450,000 Bpd to 570,000 Bpd at an estimated cost of approximately $220 million. The second phase added an additional 230,000 Bpd of capacity at an estimated cost of approximately $240 million. The initial phase was completed in the third quarter of 2014 and the second phase was completed in July 2015. Both phases of the Line 67 pipeline expansion required only the addition of pumping horsepower, with no pipeline construction, and are subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at its currently planned operating capacity of 800,000 Bpd. We continue to work with regulatory authorities; however, the timing of the receipt of the amendment to the Presidential border crossing permit to allow for increased flow on the Line 67 pipeline across the border cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining this amendment.

In November of 2014 several environmental and Native American groups filed a complaint in the United States District Court in Minnesota against the United States Department of State, or DOS. The Complaint alleges, among other things, that the DOS is in violation of the National Environmental Policy Act by acquiescing in Enbridge's use of permitted cross border capacity on other lines to achieve the transportation of amounts in excess of Line 67's current permitted capacity while the review and approval of Enbridge's application to the DOS to increase Line 67's permitted cross border capacity is still pending. On December 9, 2015, the District Court ruled that the DOS interpretation of Enbridge's Presidential permits is not reviewable by a federal court on constitutional grounds.

The current scope of the Southern Access expansion, or Line 61 expansion, between Superior, Wisconsin and Flanagan, Illinois also consists of phases that require only the addition of pumping horsepower with no pipeline construction. The initial phase to increase the capacity from 400,000 Bpd to 560,000 Bpd was completed in August 2014 at a cost of approximately $160 million. We further expanded the pipeline capacity to 800,000 Bpd in May 2015 at an estimated cost of approximately $395 million. Additional tankage is expected to cost approximately $380 million with various completion dates that began in the third quarter of 2015 and are expected to continue through the third quarter of 2016. In the first quarter of 2015, we, in conjunction with shippers, decided to delay the in-service date of a further expansion phase to increase the pipeline capacity to 1,200,000 Bpd to align more closely with the anticipated in-service date for the Sandpiper Project. In October 2015, a portion of this phase was placed into service early to address capacity constraints, increasing pipeline capacity to 950,000 Bpd. The remaining capacity is expected to be placed into service in line with the expected in-service date of the Sandpiper Project.

Furthermore, as part of the Light Oil Market Access Program, we expanded the capacity on our Lakehead System between Flanagan, Illinois, and Griffith, Indiana by constructing Line 78, a 79-mile, 36-inch diameter twin of Line 62, with an initial capacity of 570,000 Bpd, at an estimated cost of $540 million. Line 78 was placed into service in November 2015.

These projects, collectively referred to as the U.S. Mainline Expansions projects, are expected to cost approximately $2.4 billion. We will operate the projects on a cost-of-service basis. These projects are jointly funded 75% by our General Partner and 25% by us under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. We have the option to increase our economic interest held up to 15% at cost.

Canadian Eastern Access and Mainline Expansion Projects

The Eastern Access Projects and U.S. Mainline Expansions projects complement Enbridge's strategic initiative of expanding access to new markets in North America for growing production from western Canada and the Bakken Formation. Since October 2011, Enbridge also announced several complementary Eastern Access and Mainline Expansion Projects, which had various in-service dates throughout 2015. Two of these projects include reversal of Enbridge's Line 9B from Westover, Ontario to Montreal, Quebec, to serve refineries in Quebec, and an expansion of Enbridge's Line 9 to provide additional delivery capacity within Ontario and Quebec.

The Line 9B reversal and Line 9 capacity expansion projects were approved by the Canadian National Energy Board, or NEB, in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B reversal and Line 9 expansion project. On October 23, 2014, Enbridge responded to the NEB describing Enbridge's rigorous approach to risk management and isolation valve placement. On February 6, 2015, the NEB approved conditions 16 and 18, the two conditions in the NEB's order requiring approval, and Enbridge filed for the Leave to Open, or LTO, which is also a prerequisite to allowing the operation of the project. In its February approval, the NEB also imposed additional obligations on Enbridge that directs it to take a "life-cycle" approach to water crossings and valves, requiring Enbridge to perform ongoing analysis to ensure optimal protection of the area's water resources. On June 18, 2015, the NEB approved the LTO application and issued a separate order imposing further conditions requiring Enbridge to perform hydrostatic tests of selected segments of the pipeline. Enbridge filed its hydrostatic test plan with the NEB on July 23, 2015, which was approved on July 27, 2015. Hydrostatic testing was completed and Enbridge submitted the test results to the NEB in September 2015. On September 30, 2015, the NEB confirmed that the hydrostatic tests successfully met their criteria. Line fill commenced in late October 2015 and the pipeline was placed into service in December 2015.

Enbridge Market Extensions

One of our key strengths is our relationship with Enbridge. In 2014, Enbridge announced the completion of two major U.S. Gulf Coast market access pipeline projects, the Flanagan South Pipeline and Seaway Crude Pipeline, which pull more volume through our pipelines and may lead to further expansions of our Lakehead pipeline system. In 2012, Enbridge announced the Southern Access Extension, which, along with the reversal of Line 9A and Line 9B, will support the increasing supply of light oil from Canada and the Bakken into Patoka, Illinois.

Southern Access Extension

The Southern Access Extension project involves the construction of a 165-mile, 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois, with an initial capacity of 300,000 Bpd, as well as additional tankage and two new pump stations. The project was placed into service in December 2015. Lincoln Pipeline LLC, or Lincoln, an affiliate of MPC, has a 35% equity interest in the project and will make additional cash contributions in accordance with the Southern Access Extension's spend profile in proportion to its 35% interest.

Natural Gas

Our Natural Gas segment includes the operations of our Anadarko, East Texas, North Texas, and Texas Express NGL systems, as well as our trucking and marketing operations. For a detailed description of each of these systems, refer to Part I, Item I. *Business.* The following tables set forth the operating results of our Natural Gas segment and the approximate average daily volumes of natural gas throughput and NGLs produced on our systems for the years ended December 31, 2015, 2014 and 2013.

	December 31,		
	2015	2014	2013
		(in millions)	
Operating results:			
Operating revenues	$ 2,842.7	$ 5,894.3	$ 5,597.2
Commodity costs	2,372.9	5,145.9	4,948.9
Segment gross margin	469.8	748.4	648.3
Operating expenses:			
Operating and administrative	351.0	423.0	449.8
Goodwill impairment	246.7	—	—
Asset impairment	12.3	15.6	—
Depreciation and amortization	157.8	151.4	143.1
Operating expenses	767.8	590.0	592.9
Operating income (loss)	(298.0)	158.4	55.4
Other income (loss)	29.3	13.2	(1.5)
Net income (loss)	$ (268.7)	$ 171.6	$ 53.9
Operating Statistics (MMBtu/d):			
East Texas	964,000	1,030,000	1,153,000
Anadarko	773,000	827,000	949,000
North Texas	265,000	293,000	317,000
Total	2,002,000	2,150,000	2,419,000
NGL Production (Bpd)	81,632	83,675	88,236

Year ended December 31, 2015, compared with year ended December 31, 2014

The operating income of our natural gas business for the year ended December 31, 2015, decreased $456.4 million, as compared with the year ended December 31, 2014, in part due to a $246.7 million goodwill impairment charge. We performed a goodwill impairment analysis after we learned from customers during the second quarter of 2015 that reductions in drilling will be prolonged in the producing basins in which we operate due to the continued low commodity price environment. As a result of this analysis, we determined that $246.7 million in goodwill was impaired.

Decreases in ''Operating revenues'' and ''Cost of natural gas and natural gas liquids'' for the year ended December 31, 2015, as compared with the same period in 2014, are primarily due to decreases in commodity prices and the resulting decreased volumes from lower drilling activities. Segment gross margin, which decreased $278.6 for the year ended December 31, 2015, as compared with the year ended December 31, 2014, due to the following reasons:

Segment gross margin experienced a net decrease of $216.8 million, due to non-cash, mark-to-market losses of $58.3 million for the year ended December 31, 2015, including $1.6 million of gains associated with the assignments of certain natural gas contracts, as compared to gains of $158.5 million for year ended December 31, 2014. The decrease is primarily the result of a reclassification of previously recognized unrealized mark-to-market net gains where the underlying transactions were settled, coupled with decreased non-cash, mark-to-market net gains due to smaller decreases in average forward prices during 2015 than in 2014.

Segment gross margin decreased $28.0 million for the year ended December 31, 2015, as compared with the same period in December 31, 2014, due to decreased margins from lower commodity prices, net of hedges, related to contracts where we were paid in commodities for our services.

Our segment gross margin was also impacted by decreased margins within our marketing function due to natural gas pricing differentials between market centers by approximately $9.7 million for the year ended December 31, 2015, as compared to the year ended December 31, 2014. During the first quarter of 2014, we benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest which arose due to higher than usual demand from winter weather conditions in the Midwest.

Segment gross margin was affected by reduced production volumes which negatively affected segment gross margin by approximately $28.7 million for the year ended December 31, 2015, as compared to the year ended December 31, 2014. The average daily volumes of our major systems for the year ended December 31, 2015, decreased by approximately 148,000 million British thermal units per day, or MMBtu/d, or 7% when compared to the year ended December 31, 2014. The average NGL production for the year ended December 31, 2015, decreased by 2,043 Bpd, or 2%, when compared to the year ended December 31, 2014. The decrease in natural gas and NGL volumes was primarily attributable to the continued low commodity price environment for natural gas, NGLs and condensate, which has resulted in reductions in drilling activity from producers in the areas we operate.

Our segment gross margin also decreased $9.3 million for the year ended December 31, 2015, as compared with the same period in December 31, 2014. On September 1, 2015, two wholly-owned subsidiaries of Midcoast Operating in the Natural Gas segment sold certain natural gas inventories and assigned certain storage agreements, transportation contracts and other arrangements to a third party. We recognized a loss of $9.3 million in connection with this transaction, primarily related to costs to transfer certain fixed-demand storage and transportation obligations to the buyer.

Our segment gross margin decreased $8.0 million for the year ended December 31, 2015, as compared with the same period in 2014, due to lower storage margins as a result of the relative difference between the injection price paid to purchase and store natural gas, crude oil and NGLs and the withdrawal price at which these commodities are sold from storage.

Segment gross margin increased $7.4 million for the year ended December 31, 2015, as compared with the year ended December 31, 2014, due to decreased physical measurement losses as a result of system efficiencies. Physical measurement gains and losses 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

Our segment gross margin also increased $5.6 million for year ended December 31, 2015, when compared to the same period of 2014, for decreases in non-cash charges to decrease the cost basis of our natural gas inventory to net realizable value recorded in 2014.

Operating and administrative costs decreased $72.0 million for the year ended December 31, 2015, when compared to the year ended December 31, 2014 primarily due to cost reduction efforts undertaken by management, including $15.0 million in workforce reductions, which resulted in a decrease in contract labor as well as other related cost benefits. In addition, other cost reduction efforts have resulted in reduced repairs and maintenance costs.

Depreciation and amortization expense increased $6.4 million, for the year ended December 31, 2015, compared with the year ended December 31, 2014, due to additional assets that were placed into service.

Other income increased $16.1 million for the year ended December 31, 2015, compared with the year ended December 31, 2014, primarily due to increases in equity earnings on our investment in the Texas Express NGL system. These increases were a result of higher volumes and increases in ship-or-pay commitments during 2015.

Year ended December 31, 2014, compared with year ended December 31, 2013

The operating income of our Natural Gas segment for the year ended December 31, 2014, increased $103.0 million, as compared with the year ended December 31, 2013. The most significant area affected was segment gross margin, representing revenue less commodity costs, which increased $100.1 million for the year ended December 31, 2014, as compared with the year ended December 31, 2013.

Segment gross margin experienced an increase in non-cash, mark-to-market net gains of $161.5 million for the year ended December 31, 2014, compared to the year ended December 31, 2013, primarily related to non-cash, mark-to-market gains in the year ended December 31, 2014, on our NGL hedges. The values of these hedges and contracts, which help assure the prices we realize on commodities, increased as the related physical commodity value decreased.

Segment gross margin increased $15.6 million for the year ended December 31, 2014, as compared to the year ended December 31, 2013 due to increased margins from natural gas pricing differentials in the first quarter of 2014. We benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest, which arose from higher than normal demand from winter weather in the Midwest.

Segment gross margin increased $2.3 million for the year ended December 31, 2014, due to improved pricing spreads between our Conway and Mont Belvieu market hubs when compared with the year ended December 31, 2013.

Segment gross margin was affected by reduced production volumes which negatively affected segment gross margin by approximately $45.8 million for the year ended December 31, 2014, as compared to the year ended December 31, 2013. The average daily volumes of our major systems for the year ended December 31, 2014, decreased by approximately 269,000 million British thermal units per day, or MMBtu/d, or 11% when compared to the year ended December 31, 2013. The average NGL production for the year ended December 31, 2014, decreased by 4,561 Bpd, or 5%, when compared to the year ended December 31, 2013. The decrease in natural gas and NGL volumes in the Anadarko region was primarily attributable to the loss in 2013 of a major customer on our Anadarko system and delayed drilling activity by certain producers. The decrease in natural gas volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

Segment gross margin derived from keep-whole earnings for the year ended December 31, 2014, decreased $33.4 million when compared to the year ended December 31, 2013, due to a decrease in processing margins primarily driven by lower volumes in keep-whole barrels in the Oklahoma, East Texas, and Anadarko regions.

Segment gross margin decreased approximately $3.0 million for the year ended December 31, 2014, primarily due to the impact of sustained freezing temperatures in the first quarter 2014, which significantly disrupted producer wellhead production levels and our pipeline operations compared to the year ended December 31, 2013.

Operating and administrative costs decreased $26.8 million for the year ended December 31, 2014, when compared to the year ended December 31, 2013 primarily related to reduced outside contract labor, and lower rents and leases. This decrease was offset by an increase in costs from a non-cash impairment on our non-core Louisiana propylene pipeline asset of $15.6 million. The impairment charge was taken following finalization of a contract restructuring with the primary customer. In addition, in December of 2014, the company took actions to reduce its costs through a workforce reduction, which increased severance costs by $4.8 million for the year ended December 31, 2014, as compared to the year ended December 31, 2013.

Depreciation and amortization expense increased $8.3 million, for the year ended December 31, 2014, compared with the year ended December 31, 2013, due to additional assets that were placed into service.

We recognized $13.2 million in equity income in "Other income (expense)" on our consolidated statements of income related to our investment in the Texas Express NGL system. This is due to a full year of operations of the pipeline which went into service in November 2013.

Future Prospects for Natural Gas

We intend to expand our natural gas gathering and processing services by: (1) capturing opportunities within our footprint, (2) expanding outside of our footprint through strategic acquisitions, (3) providing an array of services for both natural gas and NGLs in combination with core asset optimization, and (4) capitalizing on new market opportunities by diversifying geographically and by commodity composition. We will pursue internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas business in situations where we have competitive advantages to create additional value.

Impact of Commodity Prices

Demand for our midstream services primarily depends upon the supply of natural gas and associated natural gas from crude oil development and the drilling rate for new wells. Demand for these services depends on overall economic conditions and commodity prices. Commodity prices for natural gas, NGLs, condensate and crude oil have remained low throughout 2015. The depressed commodity price environment is the most significant factor for reduced drilling activity and declining volumes in the basins in which we operate. We expect producers to continue to reduce drilling activity due to the current commodity price environment, and as a result, we expect to see a decrease in volumes in 2016. We factored these expected decreases into our fixed asset and intangible asset recoverability tests on our Anadarko, North Texas, and East Texas assets during 2015 and do not expect any impairment on these assets at this time. However, further declines in long-term volumes or reserves could affect our assessments.

We have largely mitigated our near-term direct commodity price risk through our hedging program. We have hedged approximately 90% and 40% of our direct forecasted commodity cash flow exposure for 2016 and 2017, respectively. Despite our hedging program, we still bear indirect commodity price exposure as lower drilling activity impacts the volumes on our systems as well as direct commodity price exposure for unhedged commodity positions. We expect this indirect impact on our volumes to improve as prices improve.

Expansion Projects

The following expansion projects are designed to increase natural gas processing, NGL production, residue gas and NGL transportation capacity. The paragraphs below summarize our projects that we have placed into service in 2015 or expect to place into service in future periods.

Beckville Cryogenic Processing Plant

In May 2015, we placed into service a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville Processing Plant. This plant serves 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, as well as the Eaglebine developments. Production from the Cotton Valley formation typically contains two to three gallons of NGLs per Mcf of natural gas. Our Beckville processing plant is 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. Related NGL takeaway infrastructure connecting the Beckville plant to third party NGL transportation systems was also constructed. This project cost approximately $165.0 million.

The project was funded by us and MEP based on our proportionate ownership percentages in Midcoast Operating, which are 48.4% and 51.6%, respectively.

Eaglebine Developments

The Eaglebine is an emerging oil play in East Texas that spans over five counties and is comprised of multiple formations, including but not limited to, the Woodbine, Buda, Glenrose and Eagle Ford formations. We have a series of construction projects and an acquisition in this play. We have completed construction of the Ghost Chili pipeline project, which consists of a lateral and associated facilities that create gathering capacity of over 50 MMcf/d for rich natural gas to be delivered from Eaglebine production areas to our complex of cryogenic processing facilities in East Texas. The initial facilities were placed into service in October 2015. We also expect to construct the Ghost Chili Extension Lateral to fully utilize this gathering capacity with the rest of our processing assets when additional development in the basin supports it. Given the proximity of our existing East Texas assets, this expansion into Eaglebine will allow us to offer gathering and processing services while leveraging assets on our existing footprint.

On February 27, 2015, we acquired from New Gulf Resources, LLC, or NGR, its midstream operations in Leon, Madison and Grimes counties, Texas. The acquisition consists of a natural gas gathering system currently in operation. For further details regarding the NGR acquisition, refer to Item 8. *Financial Statements and Supplementary Data*, Note 4. *Acquisitions*.

We estimate the aggregate cost of our Eaglebine projects and acquisition described above to be approximately $160.0 million, of which $116.8 million was spent in 2015. Remaining funding is to be provided by us and MEP based on our proportionate ownership percentages in Midcoast Operating, subject to market conditions and our financing capacity.

Corporate

Our corporate results consist of interest expense, interest income, allowance for equity during construction and other costs such as income taxes, which are not allocated to the business segments.

	December 31,		
	2015	2014	2013
		(in millions)	
Operating Results:			
Operating and administrative expenses	$ 14.4	$ 10.6	$ 7.6
Operating loss	(14.4)	(10.6)	(7.6)
Interest expense, net	(322.0)	(403.2)	(320.4)
Allowance for equity used during construction	70.3	57.2	43.1
Other income (expense)	—	(4.3)	17.5
Income (loss) before income tax expense	(266.1)	(360.9)	(267.4)
Income tax expense	(4.9)	(9.6)	(18.7)
Net loss	$(271.0)	$(370.5)	$(286.1)

Year ended December 31, 2015 compared with year ended December 31, 2014

The $99.5 million decrease in our net loss for the year ended December 31, 2015, as compared to the same period in 2014 was primarily attributable to a decrease in interest expense.

Interest expense decreased $81.2 million for the year ended December 31, 2015, when compared with the year ended December 31, 2014, primarily due to a decrease in the recognition of the ineffective portion of unrealized and realized losses on our pre-issuance hedges. In 2014, we recognized $100.6 million in interest expense for hedge ineffectiveness from extending the maturity dates of our pre-issuance hedges that were set to mature in 2014. In October 2015, we settled some of these pre-issuance hedges. This decrease period over period was offset by higher interest cost on newly-issued senior debt.

Year ended December 31, 2014 compared with year ended December 31, 2013

The increase in our net loss in 2014 was primarily due to an increase in interest expense to $403.2 million for the year ended December 31, 2014, compared with $320.4 million for the corresponding period in 2013. This increase in interest expense is primarily due to an increase of approximately $1.9 billion in our outstanding debt balance. Also contributing to the increase in interest expense is the recognition of unrealized losses for hedge ineffectiveness of approximately $100.1 million.

Income tax expense decreased $9.1 million for the year ended 2014 compared to the same period in 2013, primarily due to a tax law that was passed in June 2013 in the State of Texas, referred to as House Bill 500, or HB 500. The law allows a pipeline company that transports oil, gas, or other petroleum products owned by others to subtract as 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.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary operating cash requirements consist of normal operating expenses, maintenance capital expenditures, funding requirements associated with environmental costs, distributions to our partners and payments associated with our risk management activities. We expect to fund our current and future short-term cash requirements for these items from our operating cash flows supplemented as necessary by issuances of commercial paper and borrowings under our Credit Facilities. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facilities.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses through organic growth and targeted acquisitions. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our Credit Facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all. In addition, we intend to sell additional interests in Midcoast Operating to MEP to raise capital over the course of the next several years. Although this is our intent, there is no assurance that any transactions will occur as they are subject to, among other things, obtaining agreement from MEP and the board of directors of its general partner on the commercial terms of such a sale. In the past, when we had attractive growth opportunities in excess of our own capital raising capabilities, the General Partner provided supplementary funding, or participated directly in projects, to enable us to undertake such opportunities. If in the future we have attractive growth opportunities that exceed capital raising capabilities, we could seek similar arrangements from the General Partner, but there can be no assurance that this funding can be obtained.

Available Liquidity

Our primary source of short-term liquidity is provided by our $1.5 billion commercial paper program, which is supported by our $1.975 billion multi-year unsecured revolving credit facility, which we refer to as the Credit Facility, and our $625.0 million credit agreement, which we refer to as the 364-Day Credit Facility. We access our $1.5 billion commercial paper program primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

As set forth in the following table, we had approximately $1.5 billion of liquidity available to us at December 31, 2015, to meet our ongoing operational, investment and financial needs.

	EEP	MEP
	(in millions)	
Cash and cash equivalents	$ 130.1	$ 18.0
Total credit available under our Credit Facilities	2,600.0	—
Total credit available under MEP's Credit Agreement	—	810.0
Less: Amounts outstanding under our Credit Facilities	1,110.0	—
Less: Amounts outstanding under MEP's Credit Agreement	—	490.0
Principal amount of commercial paper issuances	326.1	—
Letters of credit outstanding	121.7	—
Total	$1,172.3	$338.0

As of December 31, 2015, although we had a working capital deficit of approximately $1.0 billion, we had approximately $1.5 billion of liquidity to meet our ongoing operational, investing and financing needs as described above, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil releases on Line 6B.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these activities. We have issued a balanced combination of debt and equity securities to fund our expansion projects and acquisitions. Our internal growth projects and targeted acquisitions will require additional permanent capital and require us to bear the cost of constructing and acquiring assets before we begin to realize a return on them. If market conditions change and capital markets become constrained, our ability and willingness to complete future debt and equity offerings may be limited, which in turn, could affect our ability to execute our growth strategy or complete our planned construction projects. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

From time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. In February 2015, we filed with the SEC a new shelf registration statement, or the 2015 Shelf, on Form S-3 that replaced our prior shelf registration statement which expired in December 2014. The 2015 Shelf allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

Issuance of Class A Common Units

The following table presents the net proceeds from our Class A common unit issuances for the year ended December 31, 2015. The proceeds from the March 2015 offering were used to fund a portion of our capital expansion projects and for general partnership purposes. There were no issuances of Class A common units for the years ended December 31, 2014 and 2013.

2015 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
	(in millions, except units and per unit amounts)				
March	8,000,000	$36.70	$288.8	$6.0	$294.8

(1) Net of underwriters' fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

Series 1 Preferred Units

In 2013, we issued and sold 48,000,000 Series 1 preferred units, representing limited partner interests in us, or Preferred Units, for aggregate proceeds of approximately $1.2 billion. We used proceeds from the Preferred Unit issuance to repay commercial paper, to finance a portion of our capital expansion program relating to our core liquids and natural gas systems and for general partnership purposes. On July 30, 2015, we amended our limited partnership agreement to extend the deferral of distribution payments, to extend the rate reset pricing date, and to defer the conversion option date, as discussed below.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset on June 30, 2020, and each subsequent five-year anniversary thereafter. However, these quarterly cash distributions, during the first full twenty quarters ending June 30, 2018, will accrue and accumulate, which we refer to as the Payment Deferral. These amounts will be paid in equal amounts over a twelve-quarter period beginning in the first quarter of 2019.

On or after June 1, 2018, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. For further details regarding the Preferred Units, refer to Item 8. *Financial Statements and Supplementary Dat*a, Note 11. *Partners' Capital*.

Midcoast Energy Partner, L.P.

In 2013, MEP completed the Offering of 21,725,000 Class A common units representing limited partner interests, including the underwriter's over allotment option. 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 us, 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 us.

On July 1, 2014, we sold a 12.6% limited partner interest in Midcoast Operating to MEP, for $350.0 million in cash, which reduced our total ownership interest in Midcoast Operating from 61% to 48.4%. This transaction represents our first sale to MEP of additional interests in Midcoast Operating since the Offering.

At December 31, 2015, we owned 5.9% of outstanding MEP Class A common units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 48.4% of the limited partner interests in Midcoast Operating. We intend to sell additional interests in our natural gas assets, held through Midcoast Operating, to MEP and use the proceeds from any such sale as a source of funding for us. However, we do not know when, or if, any additional interests will be offered for sale.

Investments

In March and September 2013, Enbridge Management completed public offerings of 10,350,000 and 8,424,686 Listed Shares, respectively, representing limited liability company interests with limited voting rights for net proceeds of $272.9 million and $235.6 million, respectively, Enbridge Management used those proceeds to purchase an equal number of the Partnership's i-units. We used the proceeds from our sale of i-units to Enbridge Management to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

Credit Facilities

The Credit Facility, permits aggregate borrowings of up to, at any one time outstanding, $1.975 billion, a letter of credit subfacility and a swing line subfacility. The Credit Facility matures September 26, 2020; however, $175.0 million of commitments will expire on the original maturity date of September 26, 2018.

The 364-Day Credit Facility is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $625.0 million subject to the terms and conditions set forth therein. The 364-Day Credit Facility provides aggregate lending commitments: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion, and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods, which is currently July 1, 2016.

At December 31, 2015, the Credit Facilities provide an aggregate bank credit amount of approximately $2.6 billion, which we use to fund our general activities and working capital needs.

On November 16, 2015, we received a commitment reduction notice from Enbridge (U.S.) Inc., or EUS, an affiliate of Enbridge, with respect to the credit agreement with EUS, or the EUS 364-day Credit Facility, that previously permitted aggregate borrowing of up to, at any one time outstanding, $750.0 million. EUS elected to reduce its commitment to zero following the Partnership's offering of $1.6 billion of debt securities in October of 2015. See Note 9. *Related Party Transactions* for further details.

As of December 31, 2015, we were in compliance with the terms of all of our financial covenants under the Credit Facilities. For further details regarding the Credit Facilities and the amendments thereto, refer to Item 8. *Financial Statements and Supplementary Data*, Note 10. *Debt*.

We are party to an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $175.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank's sole discretion, we view this arrangement as liquidity enhancement as it allows us to potentially reduce our reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support our hedging activities.

Commercial Paper

We are party to a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At December 31, 2015, we had $326.1 million in principal amount of commercial paper outstanding at a weighted average interest rate of 1.22%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net repayments of approximately $286.1 million during the year ended December 31, 2015, which includes gross borrowings of $12.0 billion and gross repayments of $12.3 billion. At December 31, 2014, we had $612.3 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.50%, excluding the effect of our interest rate hedging activities. Our policy is that the commercial paper we can issue is limited by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion. For further details regarding the commercial paper program, refer to Item 8. *Financial Statements and Supplementary Data*, Note 10. *Debt*.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at December 31, 2015, we could borrow approximately $1.0 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under our Credit Facilities	$2,600.0
Less: Amounts outstanding under our Credit Facilities	1,110.0
Principal amount of commercial paper outstanding	326.1
Letters of credit outstanding	121.7
Total amount available at December 31, 2015	$1,042.2

Senior Notes

On October 6, 2015, we closed a public offering of $1.6 billion of senior unsecured notes, comprised of $500 million aggregate principal amount of notes due October 15, 2020, $500 million aggregate principal amount of notes due October 15, 2025 and $600 million aggregate principal amount of notes due October 15, 2045 for net proceeds of approximately $1.575 billion after deducting underwriting discounts and commissions and estimated offering expenses. For further details regarding the senior notes, refer to Item 8. *Financial Statements and Supplementary Data*, Note 10. *Debt*.

Our senior notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $200.0 million of senior notes issued by the OLP, which we refer to as the OLP Notes. The OLP, our operating subsidiary that owns the Lakehead system, has $200.0 million of senior notes outstanding representing unsecured obligations that are structurally senior to our senior notes. The OLP Notes consist of $100.0 million of 7.000% senior notes due 2018 and $100.0 million of 7.125% senior notes due 2028. All of the OLP Notes pay interest semi-annually.

For further details regarding the OLP Notes, refer to Item 8. *Financial Statements and Supplementary Data*, Note 10. *Debt*.

Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due October 1, 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, payable semi-annually in arrears on April 1 and October 1 of each year until October 1, 2017. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month London Interbank Offered Rate, or LIBOR, for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. For further details regarding the junior subordinated notes, refer to Item 8. *Financial Statements and Supplementary Data*, Note 10. *Debt*.

MEP Credit Agreement

MEP, Midcoast Operating, and MEP's material domestic subsidiaries are parties to the MEP Credit Agreement, which is a committed syndicated senior revolving credit facility with related letter of credit and swing line facilities. On September 3, 2015, MEP amended its Credit Agreement to decrease the aggregate commitments to $810.0 million and extend the maturity date from September 30, 2017 to September 30, 2018; however, $140.0 million of commitments will expire on the initial maturity date of November 13, 2016 and an additional $25.0 million of commitments will expire on September 30, 2017.

The MEP Credit Agreement also requires compliance with two financial covenants. MEP is not permitted to allow their ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio), 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. MEP must also 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 could limit MEP's ability to undertake additional debt financing.

At December, 31, 2015, MEP was in compliance with the terms of our financial covenants in the Credit Agreement. Due to the continued decline in oil and gas prices and the potential implications on their results of operations, it is possible that MEP may not be able to meet the total leverage ratio financial covenant at some point during the remaining term of the facility. If this were to occur, MEP would seek a waiver from its lenders, seek additional capital contributions, pursue refinancing of the amounts outstanding under the Credit Agreement or seek to take other action to prevent a default under the Credit Agreement, although there is no assurance that MEP could obtain any such necessary preventative actions. Failure to comply with one or both of the financial covenants may result in the occurrence of an event of default under the Credit Agreement, which would result in a cross-default under the note purchase agreement on the Notes. If an event of default were to occur, the lenders could, among other things, terminate their commitments under the Credit Agreement, demand immediate payment of all amounts borrowed by MEP and Midcoast Operating, trigger the springing liens, and require adequate security or collateral for all outstanding letters of credit outstanding under the facility.

At December 31, 2015, MEP had $490.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 3.71%. Under the MEP Credit Agreement, MEP had net borrowings of approximately $130.0 million during the year ended December 31, 2015, which includes gross borrowings of $6.1 billion and gross repayments of $6.0 billion. At December, 31, 2015, MEP was in compliance with the terms of its financial covenants in the MEP Credit Agreement. For further details regarding the MEP Credit Agreement and the amendments thereto, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 10. *Debt*.

MEP Private Debt Issuance

In 2014, MEP completed a private offering of $400.0 million of notes consisting of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015.

The purchase agreement related to the Notes also requires compliance with two financial covenants. We must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio), 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. We 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.

At December 31, 2015, we were in compliance with the terms of our financial covenants under the Notes and the related purchase agreement. Due to the continued decline in oil and gas prices and the potential implications on our results of operations, it is possible that we may not be able to meet the total leverage ratio financial covenant at some point during the remaining term of the facility. If this were to occur, we would seek a waiver from the note holders, seek additional capital contributions, pursue refinancing of the amounts outstanding under the Notes or seek to take other action to prevent a default under the purchase agreement and the Notes, although there is no assurance that we could obtain any such necessary preventative actions. Any failure to comply with one or both of the financial covenants could result in the occurrence of an event of default under the purchase agreement and the Notes and result in a cross-default under the Credit Agreement. If an event of default were to occur, the note holders could, among other things, demand immediate payment of the Notes and trigger the springing liens.

For further details about the Notes and related private placement, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 10. *Debt*.

Maturities of Third Party Debt

The scheduled maturities of outstanding third-party debt, excluding any discounts at December 31, 2015, are summarized as follows in millions:

2016	300.0
2017	826.1
2018	990.0
2019	575.0
2020	$1,610.0
Thereafter	3,775.0
Total	$8,076.1

Joint Funding Arrangements

In order to obtain the required capital to expand our various pipeline systems, we have determined that the required funding would challenge our ability to efficiently raise capital. Accordingly, we have explored numerous options and determined that several joint funding arrangements would provide the best source of available capital to fund the expansion projects.

Joint Funding Arrangement for Alberta Clipper Pipeline

Until January 2, 2015, we had a joint funding arrangement with several of our affiliates and affiliates of Enbridge to finance the construction of the United States segment of the Alberta Clipper Pipeline. On January 2, 2015, we completed the Drop Down transaction pursuant to which the General Partner and its affiliates contributed to us the remaining 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline in exchange for approximately 18,114,975 units of a new class of limited partner interests designated as Class E units with a fair value of $767.7 million. As part of the joint funding arrangement, we repaid borrowings outstanding and payable to our General Partner under a promissory note, which we referred to as the A1 Term Note.

Amendment of OLP Limited Partnership Agreement

On July 30, 2015, the partners amended and restated the limited partnership agreement of the OLP, pursuant to which our General Partner will temporarily forego Series EA and ME, collectively, the Series, distributions commencing in the quarter ended June 30, 2015, through the quarter ending March 31, 2016. The General Partner's capital funding contribution requirements for each of those two Series, commencing in August 2015, will be reduced by the amount of its foregone cash distributions from the respective Series, until the earlier of December 31, 2016 and the date aggregate reductions in capital contributions for such Series are equal to the foregone cash distributions for such Series. To the extent that the General Partner's portion of capital contributions prior to December 31, 2016 are insufficient to cover the General Partner's foregone cash distributions for a Series, beginning with the distribution related to the first quarter of 2017 for that Series, we will receive reduced cash distributions by up to 50%, and the General Partner will receive a comparable increase in cash distributions each quarter until the General Partner has received an aggregate amount of contribution reductions and distribution increases equal to the amount of foregone cash distributions.

Joint Funding Arrangement for Eastern Access Projects

We have a joint funding arrangement with the General Partner that establishes an additional series of partnership interests in the OLP, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. Our General Partner owns 75% of the EA interests, and, except as described above in *Amendment of OLP Limited Partnership Agreement*, the Eastern Access Projects are jointly funded by our General Partner at 75% and us at 25%. Within one year of the in-service date, scheduled for mid-2016, we have the option to increase our economic interest by up to 15 percentage points. During 2015, the General Partner made equity contributions of $119.3 million to the OLP to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Joint Funding Arrangement for U.S. Mainline Expansion Projects

We have a joint funding arrangement with the General Partner that establishes another series of partnership interests in the OLP, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. Our General Partner now owns 75% of the ME interests, and, except as described above in *Amendment of OLP Limited Partnership Agreement*, the U.S. Mainline Expansion Projects are jointly funded by our General Partner at 75% and us at 25%. Within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points. During 2015, the General Partner made equity contributions of $673.3 million to the OLP to fund its equity portion of the construction costs associated with the U.S. Mainline Expansion Projects.

All other operations are captured by the Lakehead interests. For further details regarding our joint funding arrangements refer to Item 8. *Financial Statements and Supplementary Data*, Note 12. Related Party Transactions.

Sale of Accounts Receivable

We and certain of our subsidiaries are parties to a receivables purchase agreement, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. The Receivables Agreement terminates on December 30, 2016. 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 certain of our subsidiaries and certain subsidiaries of MEP that are participating sellers under the Receivables Agreement, up to an aggregate monthly maximum of $450.0 million, net of receivables that have not been collected.

For the year ended December 31, 2015, we sold and derecognized $3,710.4 million of receivables to the Enbridge subsidiary, and we received cash proceeds of $3,709.3 million. As of December 31, 2015, $317.0 million of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

For further details regarding the Receivable Agreement, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 12. *Related Party Transactions*.

Cash Requirements

Capital Spending

We incurred capital expenditures of approximately $2.2 billion for the year ended December 31, 2015, including $93.2 million of maintenance capital expenditures and $863.3 million of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. In addition, we incurred $4.2 million of contributions to fund our joint ventures. At December 31, 2015, we had approximately $678.6 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment in the future.

We categorize our capital expenditures as either maintenance capital or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful life. We also include in maintenance capital expenditures a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital will increase due to the growth of our pipeline systems and the aging of portions of these systems. Maintenance capital expenditures are expected to be funded by operating cash flows.

Expansion capital expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards. We anticipate funding expansion capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate.

We maintain a comprehensive integrity management program for our pipeline systems, which relies on the latest technologies that include internal pipeline inspection tools. These internal pipeline inspection tools identify internal and external corrosion, dents, cracking, stress corrosion cracking and combinations of these conditions. We regularly assess the integrity of our pipelines utilizing the latest generations of metal loss, caliper and crack detection internal pipeline inspection tools. We also conduct hydrostatic testing to determine the integrity of our pipeline systems. Accordingly, we incur substantial expenditures each year for our integrity management programs. We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature, while expenditures to inspect and test our pipelines are usually considered operating expenses.

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 our Credit Facilities 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.

Forecasted Expenditures

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. Due to the completion of major projects, and lower-than-anticipated spending on the Sandpiper and Line 3 Replacement projects in 2016, we expect our expansion capital expenditures to be significantly lower in 2016 than in recent years. The following table sets forth our estimated maintenance and expansion capital expenditures of $900.0 million for the year ending December 31, 2016. We expect to receive funding of approximately $430.0 million from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects. Furthermore, we expect to receive funding of approximately $55.0 million from MPC based on our joint funding arrangement for the Sandpiper Project. Although we anticipate making these expenditures in 2016, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, regulatory permitting, 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.

	Total Forecasted Expenditures(1)
	(in millions)
Liquids Projects	
Eastern Access Projects	$ 215
U.S. Mainline Expansions	360
Sandpiper	140
Line 3 Replacement	185
Liquids Integrity Program	280
Expansion Capital	100
Maintenance Capital Expenditures	60
	1,340
Less joint funding from:	
General Partner(2)	430
Third parties	55
Liquids Total	**$ 855**
Natural Gas Projects	
Expansion Capital	$ 50
Maintenance Capital Expenditures	40
	90
Less joint funding from:	
MEP	45
Natural Gas Total	**$ 45**
TOTAL	**$ 900**

(1) Amounts do not include forecasted Allowance for Funds Used During Construction, or AFUDC.

(2) Joint funding by the General Partner is based on its respective economic interests in the Eastern Access Projects and U.S. Mainline Expansions, and does not take into account the temporary adjustment to contributions and distributions pursuant to the amendment of the OLP limited partnership agreement, as described above.

Distributions

We make quarterly distributions to our General Partner and the holders of our limited partner interests in an amount equal to our "available cash." As defined in our partnership agreement, "available cash" represents for any calendar quarter, the sum of all of our cash receipts plus reductions in cash reserves established in prior quarters less cash disbursements and additions to cash reserves in that calendar quarter. We establish reserves to provide for the proper conduct of our business, to stabilize distributions to our unitholders and the General Partner and, as necessary, to comply with the terms of any of our agreements or obligations. Enbridge Management, as the delegate of our General Partner under the delegation of control agreement, computes the amount of our "available cash."

Enbridge Management, as the owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to our limited partners and General Partner, the number of i-units owned by Enbridge Management and the percentage of our total units owned by Enbridge Management will increase automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's listed and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10 trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to our General Partner.

For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units that are issued when a distribution of cash is made to our General Partner and limited partner interests is treated as a distribution of available cash. As set forth in our partnership agreement, we will not make cash distributions on our i-units, but instead will distribute additional i-units such that cash is retained and used in our operations and to finance a portion of our capital expansion projects. During 2015, we distributed a total of 4,980,552 i-units through quarterly distributions to Enbridge Management, compared with 4,562,088 and 3,769,989 in 2014 and 2013, respectively.

The following table represents cash we have retained in our business since January 2013 from the in-kind distribution of additional i-units:

Distribution Payment Date	Retained for i-units	Retained from General Partner	Total Cash Retained
		(in millions)	
2015			
November 13	$ 41.8	$0.9	$ 42.7
August 14	41.0	0.8	41.8
May 15	39.5	0.8	40.3
February 13	38.9	0.8	39.7
	$161.2	$3.3	$164.5
2014			
November 14	$ 37.3	$0.8	$ 38.1
August 14	36.7	0.7	37.4
May 15	35.3	0.7	36.0
February 14	34.6	0.7	35.3
	$143.9	$2.9	$146.8
2013			
November 14	$ 34.1	$0.7	$ 34.8
August 14	28.9	0.6	29.5
May 15	28.4	0.6	29.0
February 14	22.4	0.4	22.8
	$113.8	$2.3	$116.1

Our current annual cash distribution rate is $2.332 per unit, or $0.58300 per quarter, for the year ended December 31, 2015, compared with $2.22 per unit, or $0.55500 per quarter, for the year ended December 31, 2014. We expect that all cash distributions will be paid out of operating cash flows over the long term. However, from time to time, we may temporarily borrow under our Credit Facilities or use cash retained by issuance of payment in-kind distributions for the purpose of paying cash distributions. We may do this until we realize the full impact of assets being developed on operations or to respond to short-term aberrations in our performance caused by market disruption events or depressed commodity prices. As various projects are under construction, we expect our coverage ratio to weaken as assets under construction do not generate cash flow until they enter service and we are bearing the related financial costs. We expect that our major capital expansion projects will be accretive to distributable cash flow when they are operational and the coverage ratio to then improve. Long term sustainability of our distributions is a key focus of the management assigned to oversee our operation. Increases in our distribution rate are made when expected to be sustainable for the long-term and upon the approval of the Board of Directors of Enbridge Management.

Series AC Distributions

For periods prior to our purchase of the remaining 66.7% interest in the U.S. portion of the Alberta Clipper Pipeline, the OLP was required to pay a quarterly distribution, also referred to as the Series AC distribution amount, within 45 days of the end of each calendar quarter to the holders of the Series AC general and limited partner interests under the terms of the then OLP partnership agreement, consisting of the sum of: (1) the portion of the Series AC revenue entitlement that was collected during the quarter through the transportation rates of our Lakehead system, (2) any other cash receipts attributable to the Series AC assets collected during the quarter, and (3) any reduction during the quarter in the amount of the Series AC reserves established in any prior quarter that are not utilized by the OLP, less the sum of: (a) all cash expenses related to the Series AC assets for the quarter, (b) all cash interest expenses and principal reductions of net borrowings for the quarter attributable to Series AC liabilities, (c) any cash maintenance and pipeline integrity capital expenditures for the quarter that are properly allocable to the Series AC assets, (d) any other cash expenses for the quarter attributable to Series AC liabilities, and (e) any increase in Series AC reserves established to provide for the proper conduct of the business of the Series AC interests.

The following table presents distributions by the OLP for the years ended December 31, 2015, 2014, and 2013, to our General Partner and its affiliate, representing the noncontrolling interest in the Series AC, and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests and pursuant to the OLP's partnership agreement. Pursuant to the OLP's partnership agreement, the final ownership distribution for the Series AC interests was distributed to Series AC partners of record as of the last day of the fourth quarter of 2014.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount Paid to the noncontrolling interest	Total Series AC Distribution
			(in millions)	
2015				
January 29	February 13	$13.7	$27.5	$41.2
2014				
October 31	November 14	$10.1	$20.3	$30.4
July 31	August 14	7.4	14.8	22.2
April 30	May 15	6.6	13.1	19.7
January 30	February 14	6.4	12.8	19.2
		$30.5	$61.0	$91.5
2013				
October 31	November 14	$ 7.0	$14.1	$21.1
July 29	August 14	5.5	11.0	16.5
April 30	May 15	7.5	14.9	22.4
January 30	February 14	6.9	13.8	20.7
		$26.9	$53.8	$80.7

Distribution to Series EA Interests

The following table presents distributions paid by the OLP for the years ended December 31, 2015 and 2014, to our General Partner and its affiliate, representing the noncontrolling interest in the Series EA, and to us, as the holders of the Series EA general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series EA interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series EA Distribution
			(in millions)	
2015				
October 30	November 13	$ 76.1	$ —	$ 76.1
July 30	August 14	75.4	—	75.4
April 30	May 15	17.5	52.3	69.8
January 29	February 13	22.3	67.0	89.3
		$191.3	$119.3	$310.6
2014				
October 31	November 14	$ 14.6	$ 43.7	$ 58.3
July 31	August 14	5.6	16.7	22.3
April 29	May 15	2.5	6.5	9.0
		$ 22.7	$ 66.9	$ 89.6

Distribution to Series ME Interests

The following table presents distributions paid by the OLP for the years ended December 31, 2015 and 2014, to our General Partner and its affiliate, representing the noncontrolling interest in the Series ME, and to us, as the holders of the Series ME general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series ME interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series ME Distribution
			(in millions)	
2015				
October 30	November 13	$32.5	$ —	$32.5
July 30	August 14	19.7	—	19.7
April 30	May 15	1.5	4.5	6.0
January 29	February 13	1.8	5.2	7.0
		$55.5	$9.7	$65.2
2014				
October 31	November 14	$ 0.6	$1.9	$ 2.5

Environmental

Line 14 Corrective Action Orders

After the July 27, 2012 release of crude oil on Line 14, the PHMSA issued a Corrective Action Order on July 30, 2012 and an amended Corrective Action Order on August 1, 2012, or the PHMSA Corrective Action Orders. The PHMSA Corrective Action Orders require us to take certain corrective actions, some of which have already been completed and some that are still ongoing, as part of an overall plan for our Lakehead system.

A notable part of the PHMSA Corrective Action Orders was to hire an independent third party pipeline expert to review and assess our overall integrity program. The third party assessment included organizational issues, response plans, training and systems. An independent third party pipeline expert was contracted during the third quarter of 2012 and their work is currently ongoing. The total cost of this plan is separate from the repair and remediation costs and is not expected to have a material impact on future results of operations.

Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013 we received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of twelve months. In December 2014, PHMSA again considered the status of the pipeline in light of information acquired throughout 2014. On December 9, 2014, we received a letter from PHMSA approving our request to continue the normal operation of Line 14 without pressure restrictions.

Lakehead Line 6B Crude Oil Release

During 2015, our cash flows were affected by the approximate $37.2 million we paid for environmental remediation, restoration and cleanup activities resulting from the crude oil release that occurred in 2010 on Line 6B of our Lakehead system.

In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers during the third quarter 2013 and have since amended our lawsuit, such that it now includes only one carrier. While we believe that our claims for the remaining $103.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit. Of the remaining $103.0 million coverage limit, $85.0 million is the subject matter of a lawsuit Enbridge filed against one particular insurer and the remaining $18.0 million is awaiting resolution of arbitration, which is not scheduled to occur until the fourth quarter of 2016. While we believe that those costs are eligible for recovery, there can be no assurance we will prevail in the arbitration. For more information, refer to Note 11. *Commitments and Contingencies* of our consolidated financial statements.

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, 2015 for each of the indicated calendar years:

	Notional(1)	2016	2017	2018	2019	2020 & Thereafter	Total(2)
				(in millions)			
Swaps:							
Natural gas	13,266,817	$ —	$ 0.3	$ —	$ —	$—	$ 0.3
NGL	4,611,100	9.9	(1.3)	—	—	—	8.6
Crude Oil	2,362,220	7.9	—	—	—	—	7.9
Options:							
Natural gas – puts purchased	1,647,000	2.1	—	—	—	—	2.1
Natural gas – puts written	1,647,000	(2.1)	—	—	—	—	(2.1)
Natural gas – calls purchased	1,647,000	—	—	—	—	—	—
Natural gas – calls written	1,647,000	—	—	—	—	—	—
NGL – puts purchased	4,242,100	54.4	5.8	—	—	—	60.2
NGL – puts written	91,500	(1.5)	—	—	—	—	(1.5)
NGL – calls purchased	91,500	—	—	—	—	—	—
NGL – calls written	4,242,100	(0.3)	(0.8)	—	—	—	(1.1)
Crude Oil – puts purchased	1,352,700	27.7	10.0	—	—	—	37.7
Crude Oil – calls written	1,352,700	—	(0.6)	—	—	—	(0.6)
Forward contracts:							
Natural gas	172,133,704	(2.8)	0.1	0.1	0.1	—	(2.5)
NGL	11,656,204	3.1	—	—	—	—	3.1
Crude Oil	588,287	—	—	—	—	—	—
Totals		$98.4	$13.5	$0.1	$0.1	$—	$112.1

(1) Notional amounts for natural gas are recorded in MMBtu, whereas NGLs and crude oil are recorded in Bbl.

(2) Fair values exclude credit adjustment gains of approximately $0.1 million at December 31, 2015, as well as cash collateral received of $12.6 million.

The following table provides summarized information about the timing and estimated settlement amounts of our outstanding interest rate derivatives calculated based on implied forward rates in the yield curve at December 31, 2015 for each of the indicated calendar years:

	Notional	2016	2017	2018	2019	2020	Total[1]
				(in millions)			
Interest Rate Derivatives							
Interest Rate Swaps:							
Floating to Fixed	$2,020	$ (5.7)	$ (7.1)	$ (5.5)	$(1.3)	$—	$ (19.6)
Pre-issuance hedges	$1,350	(80.4)	(49.2)	(12.2)	—	—	(141.8)
		$(86.1)	$(56.3)	$(17.7)	$(1.3)	$—	$(161.4)

(1) Fair values exclude credit valuation adjustment gains of approximately $3.9 million at December 31, 2015.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2015:

	2016	2017	2018	2019	2020	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$697.4	$ —	$ —	$ —	$ —	$ —	$ 697.4
Power commitments[2]	20.2	20.2	20.1	19.7	17.7	132.1	230.0
Operating leases	19.3	16.7	14.8	14.2	14.0	58.9	137.9
Right-of-way	2.0	1.7	1.7	1.7	1.5	34.5	43.1
Product purchase obligations[3]	44.2	15.4	24.8	25.5	26.5	85.9	222.3
Transportation/Service contract obligations[4]	56.1	112.9	125.2	129.2	125.5	338.7	887.6
Fractionation agreement obligations[5]	75.1	74.8	74.8	74.8	75.1	156.1	530.7
Total	$914.3	$241.7	$261.4	$265.1	$260.3	$806.2	$2,749.0

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

(2) Represents commitments to purchase power in connection with our Liquids segment. We included certain power commitments with obligations that are dependent on variable components. For these commitments, we only included the determinable portion of our commitment based on the contracted usage requirement and the current applicable contract rate.

(3) Represents long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at the approximate market value at the time of delivery.

(4) Represents the minimum payment amounts for contracts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

(5) Represents the minimum payment amounts from contracts 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, 2015, 2014 and 2013 were $729.4 million, $1.9 billion and $802.7 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,		
	2015	2014	2013
		(in millions)	
Total cash provided by (used in):			
Operating activities	$ 1,030.8	$ 816.8	$ 1,212.4
Investing activities	(2,126.4)	(2,976.6)	(2,642.9)
Financing activities	1,045.8	2,192.9	1,367.4
Net increase (decrease) in cash and cash equivalents	(49.8)	33.1	(63.1)
Cash and cash equivalents at beginning of year	197.9	164.8	227.9
Cash and cash equivalents at end of period	$ 148.1	$ 197.9	$ 164.8

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

	For the year ended December 31,		
	2015	2014	2013
		(in millions)	
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 20.9	$ 1.7	$ 125.0
Due from General Partner and affiliates	(17.5)	0.7	(12.6)
Accrued receivables	182.4	(50.1)	286.1
Inventory	53.3	(10.7)	(21.2)
Current and long-term other assets	(29.5)	(47.1)	(24.1)
Due to General Partner and affiliates	46.0	22.4	79.1
Accounts payable and other	3.5	(101.1)	85.1
Environmental liabilities	(43.7)	(143.1)	(174.9)
Accrued purchases	(229.6)	(89.9)	13.8
Interest payable	24.5	6.6	4.3
Property and other taxes payable	7.2	26.1	(0.7)
Net change in working capital accounts	$ 17.5	$(384.5)	$ 359.9

Year ended December 31, 2015 compared with year ended December 31, 2014

Operating Activities

Net cash provided by our operating activities increased $214.0 million during the year ended December 31, 2015, compared with the same period in 2014, primarily due to:

- Increased cash from inventory of $64.0 million primarily resulting from an overall reduction of commodity inventories as compared with the prior year;
- Increased cash from reduced payments for environmental liabilities of $99.4 million associated with the accrual for the Line 6B crude oil release;
- Increased cash from accounts payable and other as working capital of $104.6 million resulting from general timing differences for cash payments associated with our third-party accounts, including increased payments at the end of 2014 to third-party accounts in connection with the implementation of a new accounts payable system;
- Net increased cash from accrued receivables and accrued purchases of $92.8 million primarily due to a decline in commodity prices in 2015, which resulted in net collections of cash from higher priced receivables earlier in the year;
- Increased cash from net income, after non-cash adjustments, of $49.9 million, primarily due to increased operating results in the Liquids segment; and
- Decreased cash from the cash settlement of pre-issuance hedges related to interest of $237.9 million resulting from the expiration of several large pre-issuance hedge contracts in connection with issuance of long-term debt.

Investing Activities

Net cash used in our investing activities decreased by $850.2 million during the year ended December 31, 2015, compared with 2014, primarily due to:

- Decreased cash used for additions to property, plant and equipment, net of construction payables, of $816.8 million. We placed a large number of major projects related to Eastern Access and Mainline Expansion into service in 2014 and early 2015. As a result, capital expenditures for 2015 were lower compared to 2014 as projects reached completion;
- Decreased cash provided by restricted cash of $93.0 million resulting from fewer amounts remitted to the Enbridge subsidiary for sales of our receivables in accordance with our Receivables Agreement;

- Changes in contributions to fund our joint venture investment and distributions in excess of earnings in the Texas Express NGL system. This resulted in a net decrease of cash used of $16.7 million, primarily due to higher capital spending on Texas Express in 2014 and higher distributions from Texas Express in 2015 resulting from higher volumes and demand charges; and
- Increased cash used for asset acquisitions of $84.8 million due to MEP's acquisition of NGR's midstream assets in February 2015. For further details regarding this acquisition, see Item 1. *Financial Statements and Supplementary Data*, Note 4. *Acquisitions*.

Financing Activities

Net cash provided by our financing activities decreased $1,147.1 million for the year ended December 31, 2015, compared with 2014, primarily due to:

- Decreased cash from decreased net borrowings on our credit facility of $1,105.0 million;
- Decreased cash from net repayments on the commercial paper program of $598.2 million;
- Decreased cash provided by contributions from our noncontrolling interest of $528.3 million for ownership interests in the Mainline Expansion Projects, Eastern Access Projects and Sandpiper Project;
- Decreased cash from increased repayments of $294.0 million to the General Partner for the A1 Term Note. The remaining outstanding balance of $306.0 million was repaid on January 2, 2015; and
- Decreased cash from increased distributions to our limited partners of $108.0 million and to our noncontrolling interest of $185.4 million due to phases of the Eastern Access Project and Mainline Expansion Project being placed into service.

These decreases in net cash provided by our financing activities were partially offset by the following:

- Increased cash provided by the issuance of debt of $1,177.0 million, after debt issuance costs. We issued $1.6 billion of debt during 2015 and $398.1 million of debt during 2014;
- Increased cash from our Class A unit issuance, including our General Partner's contributions, of $294.8 million in March 2015. We had no similar issuances in 2014; and
- Increased cash from reduced repayments on our long-term debt of $200.0 million.

Year ended December 31, 2014 compared with year ended December 31, 2013

Operating Activities

Net cash provided by our operating activities decreased $395.6 million for the year ended December 31, 2014, compared to the same period in 2013, primarily due to a decrease in our working capital accounts of $744.4 million coupled with non-cash items of $235.7 million. These decreases were partially offset by a $579.6 million increase in net income for the year ended December 31, 2014, as compared to 2013.

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, 2014, compared with the same period in 2013, is primarily the result of items listed below in addition to general timing differences for cash receipts and payment associated with our third-party accounts. The main items affecting our cash flows from operating assets and liabilities include the following:

- The change in accrued receivables and trade receivables during 2013 was favorable due to the sale of $275.5 million of our net accrued receivables and $90.1 million of trade receivables to a subsidiary of Enbridge pursuant to the Receivables Agreement;
- Decreased cash flows from changes in accounts payable and other was due to general timing differences for cash payments associated with our third-party accounts, including increased payments to third-party accounts at the end of 2014 due to the implementation of a new accounts payable system; and
- Decreased cash flows from changes in accrued purchases are primarily the result of lower levels of accrued purchases at December 31, 2014, which stem from lower volumes purchased at lower prices as compared to the prior year.

The above decreases were coupled with a $235.7 million decrease in our non-cash items for the year ended December 31, 2014, compared to December 31, 2013, partially offset by an increase in net income of $579.6 million. The decrease in non-cash items primarily consisted of the following:

- Decreased environmental costs of $225.9 million mainly attributed to $302.0 million in additional estimated costs recognized during 2013 related to the Line 6B crude oil release, while only recognized $85.9 million in additional estimated costs were recognized for the year ended December 31, 2014 related to the Line 6B crude oil release; and
- Increased derivative net gains of $100.6 million primarily as a result of fluctuations in commodity prices.

Partially offsetting the non-cash item decreases above were the following:

- Increased depreciation and amortization of $70.2 million due to projects placed in service in 2014;
- Decreased gains on sale of assets of $17.1 million in 2014, as there was only a sale of assets in 2013; and
- Increased asset impairment charges due to the impairment of the right of way of a Propylene pipeline for $15.6 million.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2014, increased by $333.7 million, compared to 2013, primarily due to the increased payments on our construction payables of $331.9 million coupled with increased additions to property, plant and equipment in 2014 related to various enhancement projects of $198.6 million. Partially, offsetting these increases were the following:

- Decreased cash contributions of $151.9 million combined with decreased allowance for interest during construction associated with our joint venture project, the Texas Express NGL system, as the project went into service at the end of 2013; and
- Decreased restricted cash balance of $41.8 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.

Financing Activities

Net cash provided by our financing activities increased $825.5 million for the year ended December 31, 2014, compared to 2013, primarily due to the following:

- Increased net borrowings on our commercial paper of $1.2 billion for the year ended December 31, 2014;
- Increased net proceeds from borrowings on our Credit Facilities of $850.0 million primarily attributable to borrowings under our 364-Day Credit Facility in 2014;
- Increased net proceeds from borrowings on our long-term debt of $398.1 million due to us issuing private placement debt at MEP in 2014; and
- Increased contributions from noncontrolling ownership interests in the Mainline Expansion Projects, Eastern Access Projects, Sandpiper, and from Midcoast Holdings for its ownership in MEP of $243.1 million, partially offset by increased distributions to noncontrolling interest of $100.2 million.

Offsetting the proceeds above were the following:

- Decreased net proceeds in 2014 of $1.2 billion due to no preferred unit issuances in 2014 while we had a $1.2 billion preferred unit issuance in 2013; and
- Decreased net proceeds from unit issuances, including our General Partner's contributions of $519.3 million from 2013 compared to no issuances in 2014.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

REGULATORY MATTERS

FERC Transportation Tariffs

Lakehead System

On February 27, 2015, we filed FERC Tariff No. 43.16.0, our annual rate adjustment with the FERC for the Facilities Surcharge Mechanism, or FSM, component of the Lakehead system with rates effective April 1, 2015. The FSM allows Lakehead to recover costs associated with particular shipper-approved projects through an incremental cost-of-service based surcharge that is layered on top of the base index rates. The FSM surcharge reflects our projected costs for these shipper-approved projects for 2015 and an adjustment for the difference between estimated and actual costs and throughput for the prior year. The surcharge is applicable to all volumes entering our system from the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

This tariff filing decreased our transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.10 per barrel, to approximately $2.39 per barrel. The tariff filing also decreased our transportation rate for light crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.08 per barrel, to approximately $1.98 per barrel. These decreases were primarily the result of an increase in forecasted 2015 throughput and the use of a nine-month recovery period from April through December rather than a five-month recovery period from August to December that was used for 2014. The shorter recovery period in 2014 was due to a delayed toll filing, discussed further below, as a result of negotiations with shippers concerning certain components of the tariff rate structure.

On May 29, 2015, we filed FERC tariff No. 43.17.0, with an effective date of July 1, 2015, for the Lakehead system. We increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015, in Docket No. RM93-11-000.

North Dakota System

Effective February 1, 2015, FERC tariff No. 3.6.0 established a new interconnection at Tioga, North Dakota.

Effective April 1, 2015, FERC tariff No. 3.7.0 updated the calculation of the Phase 5 Looping and Phase 6 Mainline surcharges. These surcharges are cost-of-service based surcharges that are adjusted each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing decreased our average transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.44 per barrel, to an average of approximately $1.77 per barrel. The Phase 5 Looping surcharge decreased primarily due to an increase in forecasted throughput, and the Phase 6 Mainline surcharge decreased due to an increase in forecasted throughput and in order to return prior period over-recoveries to shippers.

Effective April 22, 2015, FERC tariff No. 3.8.0 cancelled the transportation rate from Sherwood, North Dakota to Clearbrook, Minnesota, as the pipeline no longer provides service from that receipt point.

Effective July 1, 2015, FERC tariff No. 3.10.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015, in Docket No. RM93-11-000. Additionally, as per the Transportation Services Agreement, or TSA, this tariff adjusted the operating cost charge component of the committed trunkline rates to Berthold, North Dakota to the actual operating costs and throughput volumes for 2014 and the forecasted operating costs and throughput for 2015.

Also effective July 1, 2015, FERC tariff No. 3.11.0 discounted the existing uncommitted rate from Berthold (pump-over), North Dakota to Berthold, North Dakota. The new tariff rate of $0.27 per barrel reflects a rate decrease of $0.556 per barrel.

Effective December 1, 2015, FERC tariff 3.13.0 was filed to establish an initial gathering service and charge at Little Muddy (Williams County), North Dakota. The $0.1137 per barrel interconnection rate resulted from a shipper's request for a pipeline interconnection at that location.

On November 12, 2015, we filed FERC tariff 3.15.0 to cancel trunkline transportation rates from Glenburn (Renville County), North Dakota and Newburg (Bottineau County), North Dakota to Clearbrook (Clearwater County), Minnesota, as well as to cancel the gathering rate from Newburg Area, North Dakota to Newburg (Bottineau County), North Dakota, as the pipeline is no longer providing service from those receipt points.

Bakken system

Effective January 1, 2015, FERC tariff No. 3.2.0 was filed to reflect a change in the international joint rates. In accordance with FERC policy, each of the international joint rates was equal to or less than the sum of the local rates for the component movements from Berthold, North Dakota to Cromer, Manitoba.

Effective July 1, 2015, FERC tariff No. 2.2.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015, in Docket No. RM93-11-000.

Also effective July 1, 2015, FERC tariff No. 3.4.1 adjusted rates in accordance with the TSA that was included in the Petition for Declaratory Order filed on August 26, 2010, in Docket No. OR10-19-000. Additionally, as per the TSA, this tariff adjusted the operating cost charge component of the committed international joint rates to Cromer, Manitoba to the actual operating costs and throughput volumes for 2014 and the forecasted operating costs and throughput for 2015.

Ozark System

Effective July 1, 2015, FERC tariff No. 48.5.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015, in Docket No. RM93-11-000.

Effective December 1, 2015, our Ozark system filed FERC Tariff 48.6.0 to increase its rate from $0.6759 to $0.8403. This filing was made to allow for recovery of costs related to the capital expenditures required to maintain the integrity of the pipeline.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. In July 2015, the FASB delayed the effective date of the new revenue standard by one year. This accounting update is effective for annual and interim periods beginning on or after December 15, 2017, and may be applied on either a full or modified retrospective basis. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements.

Consolidation

In February 2015, the FASB issued Accounting Standards Update No. 2015-02, which addresses concerns about the current accounting for consolidation of certain legal entities. It makes targeted amendments to the current consolidation guidance and ends the deferral granted to certain entities from applying the variable interest entity, or VIE, guidance. Among other things, the amended standard revised the consolidation model and guidance for limited partnerships, which included the elimination of the presumption that a general partner should consolidate a limited partnership and the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships. This accounting update is effective for annual periods, and for interim periods within those annual periods, beginning after December 15, 2015. Early adoption is permitted, and the new standard may be adopted either retrospectively or using a modified retrospective approach. We do not anticipate that our ultimate consolidation conclusions for non-wholly-owned subsidiaries will change upon adoption of the revised guidance. However, we believe that additional VIE disclosures will be required.

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 believe the proper implementation and consistent application of all applicable accounting 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.

For a summary of our significant accounting policies, refer to Item 8. *Financial Statements and Supplementary Data*, Note 2. *Summary of Significant Accounting Policies*. We believe our critical accounting policies 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.

Liquids Revenue Recognition

Revenues of our Liquids segment are primarily derived from two sources, interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC and contract storage revenues related to our crude oil storage assets. The tariffs established for our interstate pipelines specify the amounts to be paid by shippers for transportation services we provide between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. In our Liquids segment, we generally do not own the crude oil and liquid petroleum that we transport or store, and therefore, we do not assume significant direct commodity price risk. Some long-term take-or-pay contracts contain make-up-rights. Make-up-rights are granted 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. The ''remote'' determination is a matter of management judgment that requires us to make assumptions regarding, for example, general economic conditions impacting our assets, remaining capacity on the pipeline, shipper history and other factors. Such assumptions are subject to uncertainty, and changes in conditions used to make these assumptions could result in significant changes in the timing of our revenue recognition on these contracts.

Revenue Recognition and the Estimation of Revenues and Commodity Costs

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectability is reasonably assured. We estimate our current month revenue and commodity costs 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 before our preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and commodity costs based on the best available volume and price data for natural gas or crude oil delivered and received, along with an adjustment 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 commodity costs 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.

Regulated Operations

The rates for a number of our projects are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and are subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls based on forecast volumes and costs, which is subject to uncertainty. A difference between forecast and actual results causes an over or under recovery in any given year. Under the authoritative accounting provisions applicable to our regulated operations, over or under recoveries are recognized in the financial statements in the current period. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these projects through the annual cost-of-service filings with the FERC and through toll rate adjustments with our customers.

Useful Life of Property, Plant and Equipment

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. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. Uncertainties that impact these assumptions include changes in laws and regulations that limit the estimated economic life of an asset, economic conditions and supply and demand in basins we serve. Based on the results of these assessments we may make modifications to the assumptions we use to determine our depreciation rates.

Assessment of Recoverability of Property, Plant and Equipment and Intangible Assets

We evaluate the recoverability of our property, plant and equipment and intangible assets 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. 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 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. If the total of the undiscounted future cash flows is less than the carrying amount of the property, plant and equipment or intangible assets, we write the assets down to fair value. 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 intangible assets and the recognition of an impairment loss in our consolidated statements of income.

We believe the assumptions used in evaluating recoverability of our assets are appropriate and result in reasonable estimates of the fair values of our assets. However, the assumptions used are subject to uncertainty, and declines in the future performance or cash flows of our assets, changes in business conditions, such as commodity prices and drilling, or increases to our weighted average cost of capital assumptions due to changes in credit or equity markets may result in the recognition of impairment charges, which could be significant.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding commodity costs of natural gas and natural gas liquids we purchase for processing. 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 record all derivative financial instruments at fair market value in our consolidated statements of financial position, which we adjust on a recurring basis 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, or the ‘‘market approach,’’ to value substantially all of our derivative instruments.

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.

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.

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 ‘‘Environmental liabilities’’ and ‘‘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. We believe that the estimates discussed herein are reasonable, however actual results could differ and it could result in material adjustments in results of operations between periods.

SUBSEQUENT EVENTS

Distribution to Partners

On January 29, 2016, the board of directors of Enbridge Management declared a distribution payable to our partners on February 12, 2016. The distribution was paid to unitholders of record as of February 5, 2016, of our available cash of $259.6 million at December 31, 2015, or $0.5830 per limited partner unit. Of this distribution, $216.0 million was paid in cash, $42.7 million was distributed in i-units to our i-unitholder and $0.9 million was retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series EA Interests

On January 29, 2016, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP paid the entire $79.2 million distribution to us.

Distribution to Series ME Interests

On January 29, 2016, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series ME interests, declared a distribution payable to the holders of the Series ME general and limited partner interests. The OLP paid the entire $40.8 million distribution to us.

Distribution from MEP

On January 28, 2016, 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 to their partners on February 12, 2016. The distribution was paid to unitholders of record as of February 5, 2016, of MEP's available cash of $16.5 million at December 31, 2014, or $0.3575 per limited partner unit. MEP paid $7.6 million to their public Class A common unitholders, while $8.9 million in the aggregate was paid to us with respect to our Class A common units, subordinated units and to Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On January 28, 2016, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of February 5, 2016. Midcoast Operating paid $25.9 million to us and $27.6 million to MEP.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

INTEREST RATE RISK

We utilize both fixed and variable interest rate debt and are exposed to market risk resulting from the variable interest rates on our Credit Facility. To the extent that we frequently issue and re-issue commercial paper at short-term interest rates and have amounts drawn under our Credit Facility at floating rates of interest, our earnings and cash flows are exposed to changes in interest rates. This exposure is managed through periodically refinancing floating-rate bank debt with long-term fixed rate debt and through the use of interest rate derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in USD. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments.

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our fixed and variable rate debt obligations are issued. 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, 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.

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at December 31, 2015.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[(1)]	Fair Value[(2)] December 31, 2015	Fair Value[(2)] December 31, 2014
		(dollars in millions)			
Contracts maturing in 2016					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 90	0.55%	$ —	$ (0.1)
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$500	2.21%	$ (7.0)	$(12.9)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$810	2.24%	$ (6.6)	$ (1.3)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$620	2.96%	$ (6.0)	$ (3.3)
Contracts settling prior to maturity					
2016 – Pre-issuance Hedges	Cash Flow Hedge	$500	4.21%	$(80.4)	$(63.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	$500	3.69%	$(49.2)	$(36.0)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$350	3.08%	$(12.2)	$ (4.9)

(1) Interest rate derivative contracts are based on the one-month or three-month LIBOR.

(2) The fair value is determined from quoted market prices at December 31, 2015 and 2014, 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 adjustment gains of approximately $3.9 million and $37.4 million at December 31, 2015 and 2014, respectively.

	Notional	2016	2017	2018	2019	2020	Total[(1)]
				(in millions)			
Interest Rate Derivatives							
Interest Rate Swaps:							
Floating to Fixed	$2,020	$ (5.7)	$ (7.1)	$ (5.5)	$(1.3)	$—	$ (19.6)
Pre-issuance hedges	$1,350	(80.4)	(49.2)	(12.2)	—	—	(141.8)
		$(86.1)	$(56.3)	$(17.7)	$(1.3)	$—	$(161.4)

(1) Fair values exclude credit valuation adjustment gains of approximately $3.9 million at December 31, 2015.

COMMODITY PRICE RISK

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 sales and the corresponding commodity costs of natural gas and natural gas liquids we purchase for processing. Our exposure to commodity price risk exists within each 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 volatility to our cash flows. Actively traded external market quotes, data from pricing services and published indices are used to value our derivative instruments. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts. 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.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at December 31, 2015 and 2014.

	At December 31, 2015						At December 31, 2014	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2016					(in millions)			
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 2.52	$ 3.48	$ —	$ —	$—	$(0.1)
	NGL	1,482,500	$20.77	$26.39	$ 0.2	$ (8.4)	$—	$ —
	Crude Oil	475,950	$40.58	$77.56	$ —	$(17.5)	$—	$(8.1)
Receive fixed/pay variable	NGL	1,958,600	$31.91	$22.62	$18.3	$ (0.2)	$9.3	$ —
	Crude Oil	791,270	$73.34	$41.13	$25.4	$ —	$9.1	$ —
Receive variable/pay variable	Natural Gas	5,124,000	$ 2.50	$ 2.49	$ 0.1	$ (0.1)	$0.5	$(0.3)
Physical Contracts								
Receive variable/pay fixed	NGL	180,000	$31.22	$32.31	$ —	$ (0.2)	$—	$ —
	Crude Oil	55,166	$37.69	$40.61	$ —	$ (0.2)	$—	$ —
Receive fixed/pay variable	NGL	838,119	$28.52	$26.54	$ 1.9	$ (0.2)	$—	$ —
	Crude Oil	13,316	$36.40	$37.46	$ —	$ —	$—	$ —
Receive variable/pay variable	Natural Gas	165,210,634	$ 2.30	$ 2.31	$ —	$ (2.8)	$0.7	$(0.4)
	NGL	10,638,085	$16.53	$16.37	$ 4.0	$ (2.4)	$—	$ —
	Crude Oil	519,805	$37.16	$36.79	$ 0.7	$ (0.5)	$—	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	76,530	$ 2.48	$ 2.97	$ —	$ —	$—	$ —
	NGL	547,500	$17.38	$25.86	$ —	$ (4.5)	$—	$ —
	Crude Oil	547,500	$46.47	$66.72	$ —	$(10.9)	$—	$ —
Receive fixed/pay variable	NGL	622,500	$21.61	$16.28	$ 3.3	$ (0.1)	$0.7	$ —
	Crude Oil	547,500	$66.78	$46.47	$10.9	$ —	$0.8	$ —
Receive variable/pay variable	Natural Gas	8,050,000	$ 2.64	$ 2.60	$ 0.5	$ (0.2)	$—	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 2.81	$ 2.79	$ 0.1	$ —	$0.2	$(0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 2.98	$ 2.95	$ 0.1	$ —	$—	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.14	$ 3.11	$ 0.1	$ —	$—	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.45	$ 3.42	$ —	$ —	$—	$ —

(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, 2015 and 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains of approximately $0.5 million and losses of approximately $0.5 million at December 31, 2015 and 2014, respectively, as well as cash collateral received.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2015 and 2014.

	At December 31, 2015						At December 31, 2014	
					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 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 2.49	$ 2.1	$ —	$ 1.0	$ —
	NGL	2,964,600	$39.29	$21.04	$54.4	$ —	$39.3	$ —
	Crude Oil	805,200	$75.91	$41.45	$27.7	$ —	$14.7	$ —
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 2.49	$ —	$ —	$ —	$(0.1)
	NGL	2,964,600	$45.09	$21.04	$ —	$(0.3)	$ —	$(3.2)
	Crude Oil	805,200	$86.68	$41.45	$ —	$ —	$ —	$(2.7)
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 2.49	$ —	$(2.1)	$ —	$(1.0)
	NGL	91,500	$39.06	$22.94	$ —	$(1.5)	$ —	$ —
Calls (purchased)	Natural Gas	1,647,000	$ 4.98	$ 2.49	$ —	$ —	$ 0.1	$ —
	NGL	91,500	$46.41	$22.94	$ —	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,277,500	$25.26	$22.13	$ 5.8	$ —	$ 1.2	$ —
	Crude Oil	547,500	$63.00	$46.47	$10.0	$ —	4.1	$ —
Calls (written)	NGL	1,277,500	$29.46	$22.13	$ —	$(0.8)	$ —	$(0.7)
	Crude Oil	547,500	$71.45	$46.47	$ —	$(0.6)	$ —	$(3.3)

(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, 2015 and 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment losses of approximately $0.4 million and $0.7 million at December 31, 2015 and 2014, respectively, as well as cash collateral received.

COUNTERPARTY CREDIT RISK

We are subject to the risk of loss resulting from the possibility that the counterparties, of our hedging contracts, may prove unable or unwilling to perform its obligations under the contracts, particularly during periods of weak and volatile economic conditions. 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 interest rate and commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. 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. 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. 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.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS, SUPPLEMENTARY INFORMATION AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES ENBRIDGE ENERGY PARTNERS, L.P.

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 Enbridge Energy Partners, L.P.:

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, of comprehensive income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A of the Partnership's 2015 Annual Report on Form 10-K. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 17, 2016

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the year ended December 31,		
	2015	2014	2013
	(in millions, except per unit amounts)		
Operating revenues:			
Commodity sales (Note 14)	$2,573.4	$5,487.8	$5,155.4
Commodity sales – affiliate (Note 12)	73.0	206.1	213.1
Transportation and other services (Note 14)	2,369.6	2,191.8	1,690.0
Transportation and other services – affiliate (Note 12)	130.1	79.0	58.6
	5,146.1	7,964.7	7,117.1
Operating expenses:			
Commodity costs (Notes 6 and 14)	2,295.1	5,026.7	4,829.4
Commodity costs – affiliate (Note 12)	77.8	119.2	119.5
Environmental costs, net of recoveries (Note 13)	3.1	97.3	273.7
Operating and administrative (Notes 7 and 13)	501.2	462.4	480.8
Operating and administrative – affiliate (Note 12)	470.1	472.0	437.6
Power (Note 14)	259.5	226.6	147.7
Goodwill impairment (Note 8)	246.7	—	—
Asset impairment (Note 7)	74.8	15.6	—
Depreciation and amortization (Note 7)	536.2	458.2	388.0
	4,464.5	6,878.0	6,676.7
Operating income	681.6	1,086.7	440.4
Interest expense, net (Notes 10 and 14)	(322.0)	(403.2)	(320.4)
Allowance for equity used during construction (Note 17)	70.3	57.2	43.1
Other income (Notes 13 and 17)	29.3	8.9	16.0
Income before income tax expense	459.2	749.6	179.1
Income tax expense (Note 15)	(4.9)	(9.6)	(18.7)
Net income	454.3	740.0	160.4
Less: Net income attributable to:			
Noncontrolling interest (Note 12)	221.1	263.3	88.3
Series 1 preferred unit distributions	90.0	90.0	58.2
Accretion of discount on Series 1 preferred units	11.2	14.9	9.2
Net income attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 132.0	$ 371.8	$ 4.7
Net income (loss) allocable to common units and i-units	$ (84.8)	$ 218.4	$ (122.7)
Net income (loss) per common unit and i-unit (basic and diluted) (Note 3)	$ (0.25)	$ 0.67	$ (0.39)
Weighted average common units and i-units outstanding (basic and diluted)	339.1	328.2	316.2
Cash distributions paid per limited partner unit outstanding	$ 2.31	$ 2.20	$ 2.17

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the year ended December 31,		
	2015	2014	2013
		(in millions)	
Net income	$ 454.3	$ 740.0	$160.4
Other comprehensive income (loss), net of tax (Note 14)	(164.4)	(127.7)	243.9
Comprehensive income	289.9	612.3	404.3
Less:			
Net income attributable to noncontrolling interest (Note 12)	221.1	263.3	88.3
Net income attributable to Series 1 preferred unit distributions	90.0	90.0	58.2
Net income attributable to accretion of discount on Series 1 preferred units	11.2	14.9	9.2
Other comprehensive income (loss) allocated to noncontrolling interest	(5.8)	7.1	(0.9)
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (26.6)	$ 237.0	$247.7

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the year ended December 31, 2015	2014	2013
		(in millions)	
Cash provided by operating activities:			
Net income	$ 454.3	$ 740.0	$ 160.4
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (Note 7)	536.2	458.2	388.0
Derivative fair value net (gains) losses (Note 14)	(25.1)	(72.0)	28.6
Inventory market price adjustments (Note 6)	5.8	11.4	3.4
Asset impairment (Note 7)	74.8	15.6	—
Environmental costs, net of recoveries (Note 13)	5.6	82.2	308.1
Distributions from investment in joint ventures (Note 12)	29.2	12.2	—
Equity earnings from investment in joint ventures (Note 12)	(29.2)	(13.2)	—
Income taxes (Note 15)	3.8	7.8	22.9
Goodwill impairment (Note 8)	246.7	—	—
Allowance for equity used during construction (Note 17)	(70.3)	(57.2)	(43.1)
Amortization of debt issuance and hedging costs	17.7	9.4	10.5
Loss (gain) on sale of assets	3.2	—	(17.1)
Other	(1.1)	7.3	(3.9)
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	20.9	1.7	125.0
Due from General Partner and affiliates	(17.5)	0.7	(12.6)
Accrued receivables	182.4	(50.1)	286.1
Inventory (Note 6)	53.3	(10.7)	(21.2)
Current and long-term other assets (Note 14)	(29.5)	(47.1)	(24.1)
Due to General Partner and affiliates (Note 12)	46.0	22.4	79.1
Accounts payable and other (Notes 5 and 14)	3.5	(101.1)	85.1
Environmental liabilities (Note 13)	(43.7)	(143.1)	(174.9)
Accrued purchases	(229.6)	(89.9)	13.8
Interest payable	24.5	6.6	4.3
Property and other taxes payable	7.2	26.1	(0.7)
Settlement of interest rate derivatives (Note 14)	(238.3)	(0.4)	(5.3)
Net cash provided by operating activities	1,030.8	816.8	1,212.4
Cash used in investing activities:			
Additions to property, plant and equipment (Notes 7 and 18)	(2,116.8)	(2,933.6)	(2,409.9)
Changes in restricted cash (Note 12)	65.4	(27.6)	(69.4)
Asset acquisitions	(85.0)	(0.2)	(0.9)
Proceeds from the sale of net assets	6.6	—	44.7
Investment in joint ventures (Note 12)	(4.2)	(36.7)	(188.6)
Distributions from investment in joint ventures in excess of cumulative earnings	12.0	27.8	—
Other	(4.4)	(6.3)	(18.8)
Net cash used in investing activities	(2,126.4)	(2,976.6)	(2,642.9)
Cash provided by financing activities:			
Net proceeds from Series 1 preferred unit issuance (Note 11)	—	—	1,199.2
Net proceeds from unit issuances (Note 11)	294.8	—	519.3
Distributions to partners (Note 11)	(835.9)	(727.9)	(708.9)
Repayments to General Partner (Note 12)	(306.0)	(12.0)	(12.0)
Proceeds from issuance of long-term debt, net of discounts (Note 10)	1,600.0	398.1	—
Repayments on long-term debt (Note 10)	—	(200.0)	(200.0)
Net borrowings under credit facilities (Note 10)	80.0	1,185.0	335.0
Net commercial paper borrowings (repayments) (Note 10)	(286.1)	312.1	(859.9)
Debt issuance costs (Note 10)	(24.9)	—	—
Contribution from noncontrolling interest (Notes 11 and 12)	863.3	1,391.6	1,148.5
Distributions to noncontrolling interest (Notes 11 and 12)	(339.4)	(154.0)	(53.8)
Net cash provided by financing activities	1,045.8	2,192.9	1,367.4
Net increase (decrease) in cash and cash equivalents	(49.8)	33.1	(63.1)
Cash and cash equivalents at beginning of year	197.9	164.8	227.9
Cash and cash equivalents at end of period	$ 148.1	$ 197.9	$ 164.8

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2015	December 31, 2014
	(in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 5)	$ 148.1	$ 197.9
Restricted cash (Notes 4, 12 and 14)	37.6	97.0
Receivables, trade and other, net of allowance for doubtful accounts of $2.5 and $1.8 in 2015 and 2014, respectively (Notes 2 and 12)	25.2	46.2
Due from General Partner and affiliates	59.4	41.4
Accrued receivables	77.9	260.3
Inventory (Note 6)	35.1	94.2
Other current assets (Note 14)	173.0	218.4
	556.3	955.4
Property, plant and equipment, net (Notes 7 and 17)	17,412.4	15,692.7
Goodwill (Note 8)	—	246.7
Intangible assets, net (Note 9)	280.0	254.8
Other assets, net (Note 14)	567.1	597.3
	$18,815.8	$17,746.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 12)	$ 190.9	$ 143.7
Accounts payable and other (Notes 5, 14 and 17)	654.9	777.7
Environmental liabilities (Note 13)	95.8	141.7
Accrued purchases	146.1	375.7
Interest payable	98.9	74.6
Property and other taxes payable (Note 15)	103.7	96.5
Note payable to General Partner (Note 12)	—	306.0
Current maturities of long-term debt (Note 10)	300.0	—
	1,590.3	1,915.9
Long-term debt (Note 10)	7,769.9	6,675.2
Due to General Partner and affiliates (Note 12)	238.3	148.3
Other long-term liabilities (Notes 7, 13, 14 and 15)	305.2	278.1
	9,903.7	9,017.5
Commitments and contingencies (Note 13)		
Partners' capital: (Notes 11 and 12):		
Series 1 preferred units (48,000,000 outstanding at December 31, 2015 and 2014)	1,186.8	1,175.6
Class D units (66,100,000 outstanding at December 31, 2015 and 2014)	2,517.6	2,516.8
Class E units (18,114,975 outstanding at December 31, 2015)	778.2	—
Class A common units (262,208,428 and 254,208,428 outstanding at December 31,2015 and 2014, respectively)	—	235.5
Class B common units (7,825,500 outstanding at December 31, 2015 and 2014)	—	—
i-units (73,285,739 and 68,305,187 outstanding at December 31, 2015 and 2014, respectively)	212.6	712.6
Incentive distribution units (1,000 outstanding at December 31, 2015 and 2014)	495.0	493.0
General Partner	147.4	198.3
Accumulated other comprehensive loss (Note 14)	(370.0)	(211.4)
Total Enbridge Energy Partners, L.P. partners' capital	4,967.6	5,120.4
Noncontrolling interest (Note 12)	3,944.5	3,609.0
Total partners' capital	8,912.1	8,729.4
	$18,815.8	$17,746.9

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

	For the year ended December 31,					
	2015		2014		2013	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
Series 1 preferred units:						
Beginning balance	48,000,000	$1,175.6	48,000,000	$ 1,160.7	—	$ —
Allocation of proceeds and issuance costs from unit issuances	—	—	—	—	48,000,000	1,199.2
Net income allocation	—	90.0	—	90.0	—	58.2
Distributions payable	—	(90.0)	—	(90.0)	—	(58.2)
Accretion of discount on preferred units	—	11.2	—	14.9	—	9.2
Beneficial conversion feature of preferred units	—	—	—	—	—	(47.7)
Ending balance	48,000,000	1,186.8	48,000,000	1,175.6	48,000,000	1,160.7
Class D units:						
Beginning balance	66,100,000	2,516.8	—	—	—	—
Net income allocation	—	153.2	—	106.5	—	—
Issuance of Class D Units	—	—	66,100,000	2,480.1	—	—
Distributions	—	(152.4)	—	(69.8)	—	—
Ending balance	66,100,000	2,517.6	66,100,000	2,516.8	—	—
Class E units:						
Beginning balance	—	—	—	—	—	—
Net income allocation	—	42.0	—	—	—	—
Issuance of Class E Units	18,114,975	767.7	—	—	—	—
Distributions	—	(31.5)	—	—	—	—
Ending balance	18,114,975	778.2	—	—	—	—
Class A common units:						
Beginning balance	254,208,428	235.5	254,208,428	2,979.0	254,208,428	3,590.2
Net income (loss) allocation	—	311.3	—	165.8	—	(96.3)
Allocation of proceeds and issuance costs from unit issuances	8,000,000	288.8	—	—	—	—
Allocation of fair value to Class D and Class E units	—	(235.5)	—	(2,255.6)	—	—
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.	—	—	—	(95.2)	—	—
Distributions	—	(600.1)	—	(558.5)	—	(552.6)
Beneficial conversion feature of preferred units	—	—	—	—	—	37.7
Ending balance	262,208,428	—	254,208,428	235.5	254,208,428	2,979.0
Class B common units:						
Beginning balance	7,825,500	—	7,825,500	65.3	7,825,500	83.9
Net income (loss) allocation	—	18.1	—	13.4	—	(2.8)
Allocation of proceeds and issuance costs from unit issuances	—	—	—	—	—	—
Allocation of fair value to Class D and Class E units	—	—	—	(58.5)	—	—
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.	—	—	—	(2.9)	—	—
Distributions	—	(18.1)	—	(17.3)	—	(17.0)
Beneficial conversion feature of preferred units	—	—	—	—	—	1.2
Ending balance	7,825,500	—	7,825,500	—	7,825,500	65.3

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL – (continued)

	For the year ended December 31,					
	2015		2014		2013	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
i-units:						
Beginning balance	68,305,187	712.6	63,743,099	1,291.9	41,198,424	801.8
Net income (loss) allocation	—	(379.7)	—	43.6	—	(26.3)
Allocation of proceeds and issuance costs from unit issuances	—	—	—	—	18,774,686	508.5
Allocation of fair value to Class D and Class E units	—	(120.3)	—	(598.1)	—	—
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.	—	—	—	(24.8)	—	—
Distributions	4,980,552	—	4,562,088	—	3,769,989	—
Beneficial conversion feature of preferred units	—	—	—	—	—	7.9
Ending balance	73,285,739	212.6	68,305,187	712.6	63,743,099	1,291.9
Incentive distribution units:						
Beginning balance	1,000	493.0	—	—	—	—
Net income allocation	—	19.0	—	4.1	—	—
Issuance of incentive distribution units	—	—	1,000	491.7	—	—
Distributions	—	(17.0)	—	(2.8)	—	—
Ending balance	1,000	495.0	1,000	493.0	—	—
General Partner:						
Beginning balance		198.3		301.5		299.0
Net income allocation		(31.9)		38.4		130.1
General Partner contribution		—		—		10.8
Allocation of net proceeds from unit issuance		6.0		—		—
Allocation of fair value to Class D and Class E units		(8.2)		(59.6)		—
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.		—		(2.5)		—
Distributions		(16.8)		(79.5)		(139.3)
Beneficial conversion feature of preferred units		—		—		0.9
Ending balance		147.4		198.3		301.5
Accumulated other comprehensive income:						
Beginning balance		(211.4)		(76.6)		(320.5)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings		(3.1)		22.0		27.1
Unrealized net gain (loss) loss on derivative financial instruments		(155.5)		(156.8)		216.8
Ending balance		(370.0)		(211.4)		(76.6)
Total Enbridge Energy Partners, L.P. partners' capital at December 31		4,967.6		5,120.4		5,721.8
Noncontrolling interest:						
Beginning balance		3,609.0		1,975.6		793.5
Capital contributions		863.3		1,391.6		793.6
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.		—		125.4		—
Issuance of MEP units		—		—		354.9
Allocation of fair value of Class E units		(403.7)		—		—
Comprehensive income:						
Net income allocation		221.1		263.3		88.3
Other comprehensive income, net of tax		(5.8)		7.1		(0.9)
Distributions		(339.4)		(154.0)		(53.8)
Ending balance		3,944.5		3,609.0		1,975.6
Total partners' capital at December 31		$8,912.1		$8,729.4		$7,697.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND NATURE OF OPERATIONS

General

We, together with our consolidated subsidiaries, are a publicly-traded Delaware limited partnership. We are a geographically and operationally diversified organization that provides crude oil and liquid petroleum gathering, transportation and storage services, and natural gas gathering, treating, processing, marketing and transportation services in the Gulf Coast and Mid-Continent regions of the United States of America. We hold our assets in a series of limited liability companies and limited partnerships that we own either directly or indirectly. Our Class A common units are traded on the NYSE, under the symbol ''EEP.''

We were formed in 1991 by our General Partner, which is an indirect, wholly-owned subsidiary of Enbridge. We own and operate the crude oil and liquid petroleum transportation assets of the OLP, 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.

Midcoast Energy Partners, L.P.

MEP is a publicly-traded Delaware limited partnership formed by us to serve as our primary vehicle for owning and growing our 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 Class A common units representing limited partner interests. The Class A common units are traded on the NYSE under the ticker symbol ''MEP.'' MEP is a consolidated subsidiary.

On July 1, 2014, we sold a 12.6% limited partner interest in Midcoast Operating, to MEP, for $350.0 million in cash, which reduced our total ownership interest in Midcoast Operating from 61% to 48.4%. The change in our total ownership interest in Midcoast Operating was recorded as an equity transaction, and no loss on the sale was recognized in our consolidated statements of income or comprehensive income. The increase in MEP's ownership interest in Midcoast Operating resulted in a reclassification of $125.4 million from the partners' capital accounts on a pro-rata basis to ''Noncontrolling interest'' in our consolidated statements of financial position.

At December 31, 2015, our total ownership interest in MEP was approximately 53.8%, which includes 2.9% of MEP's Class A common units, 100% of MEP's outstanding subordinated units, and 100% of MEP's general partner. In addition, we directly own 48.4% of the limited partner interests in Midcoast Operating.

Enbridge Energy Management, L.L.C.

Enbridge Management is a Delaware limited liability company that was formed in May 2002. Our General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of its directors. Enbridge Management's listed shares are traded on the NYSE under the symbol ''EEQ.'' Enbridge Management owns all of a special class of our limited partner interests that we refer to as i-units and derives all of its earnings from its investment in us.

Enbridge Management's principal activity is managing our business and affairs pursuant to a delegation of control agreement among our General Partner, Enbridge Management and us. The delegation of control agreement provides that Enbridge Management will not amend or propose to amend our partnership agreement, allow a merger or consolidation involving us, allow a sale or exchange of all or substantially all of our assets or dissolve or liquidate us without the approval of our General Partner. In accordance with its limited liability company agreement, Enbridge Management's activities are restricted to being our limited partner and managing our business and affairs.

Enbridge Inc.

Enbridge is the indirect parent of our General Partner, and its common shares are publicly traded on the NYSE in the United States and the Toronto Stock Exchange, or TSX, in Canada 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 and natural gas distribution. At December 31, 2015 and 2014, Enbridge and its consolidated subsidiaries held an effective 42.2% and 40.9% outstanding ownership interest in us, respectively, through its ownership in Enbridge Management and our General Partner.

1. ORGANIZATION AND NATURE OF OPERATIONS – (continued)

Business Segments

We conduct our business through two operating segments: Liquids and Natural Gas.

Liquids

Our Liquids segment includes the Lakehead, North Dakota and the Mid-Continent crude oil systems. Our Lakehead system consists of a series of interstate common carrier crude oil and liquid petroleum pipelines that are regulated by the FERC, and storage assets, all of which are located in the Great Lakes and Midwest regions of the United States. Our Lakehead system, together with the Enbridge system in Canada owned by Enbridge, forms the longest liquid petroleum pipeline in the world. The Lakehead system, which spans approximately 2,211 miles and includes approximately 5,022 miles of pipe, has been in operation for more than 60 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The Lakehead system primarily serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. Our North Dakota crude oil system is approximately 683 miles long, has 23 pump stations, multiple delivery points and storage facilities with an aggregate working storage capacity of approximately 1.8 million barrels. The North Dakota system connects directly into the Lakehead system in the state of Minnesota. Our Mid-Continent system consists of approximately 433 miles of crude oil pipelines, including the FERC-regulated Ozark pipeline and approximately 23.6 million barrels of storage capacity, which serve refineries in the United States Mid-Continent region from Cushing, Oklahoma.

Natural Gas

Our Natural Gas segment consists of natural gas and NGL, rail and liquid marketing services, gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities, predominantly located in active producing basins in east and north Texas, as well as the Texas Panhandle and western Oklahoma. At December 31, 2015, our Natural Gas segment is comprised of five active and five standby natural gas treating plants and 17 active and eight standby natural gas processing plants, excluding plants that are inactive based on current volumes. In addition, our Natural Gas segment includes approximately 10,900 miles of natural gas and NGL gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting NGLs, crude oil and carbon dioxide.

Our Natural Gas segment provides natural gas supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines as well as other interconnected natural gas pipeline systems. We primarily provide marketing services to increase the utilization of our natural gas pipelines, realize incremental income on gas purchased at the wellhead and provide value-added services to customers.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

We prepare our consolidated financial statements in accordance with generally accepted accounting principles 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 all accounts on a consolidated basis of: (1) our wholly and majority-owned subsidiaries; and (2) our subsidiaries over which we have control, even if we do not have a majority ownership. 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 in the entity. All significant

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

intercompany accounts and transactions have been eliminated in consolidation. Interests in our subsidiaries owned by other parties that do not control the entity are presented in our consolidated financial statements as activities and balances attributable to noncontrolling interests.

Equity Investment in Joint Venture

Our Natural Gas segment includes our 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties, representing a 593-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.

Accounting for Regulated Operations

Our interstate liquids pipelines are subject to regulation by the Federal Energy Regulatory Commission, or FERC, and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates, underlying accounting practices and ratemaking agreements with customers.

The recovery of construction, operating and other costs associated with portions of our Lakehead system are subject to the authoritative accounting provisions applicable to regulated operations. Accordingly, we record costs that are allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a non-regulated entity. Also, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities.

Allowance for Funds Used During Construction

During the construction of our pipelines that qualify for regulated accounting, we are allowed to capitalize costs that represent the estimated debt and equity costs of capital necessary to finance the construction of our pipelines. The debt and equity costs, referred to collectively as allowance for funds used during construction, or AFUDC, are capitalized as part of the costs of pipeline construction in ''Property, plant and equipment, net'' in our consolidated statements of financial position. The equity return component and interest costs related to the AFUDC are credited to ''Allowance for equity used during construction'' and ''Interest expense,'' respectively, on our consolidated statements of income. Entities that do not qualify for regulated accounting are only allowed to capitalize interest costs related to its construction activities, while a component for equity is prohibited.

Regulated Operations

The rates for a number of our projects are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and are subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls based on forecast volumes and costs. A difference between forecast and actual results causes an over or under recovery in any given year. Under the authoritative accounting provisions applicable to our regulated operations, over or under recoveries are recognized in the financial statements in the current period. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these projects through the annual cost-of-service filings with the FERC and through toll rate adjustments with our customers.

Regulatory Assets and Liabilities

Under our cost-of-service recovery model, the difference between forecast and actual results causes an over or under recovery in any given year that is deferred through a revenue adjustment and is returned to or recovered from shippers through future rate adjustments in the following year. Due to these over or under recovery adjustments made in accordance with the FERC's authoritative guidance, we recognize assets and liabilities for regulatory purposes. The assets and liabilities that we recognize for regulatory purposes are recorded on a net basis in ''Other current assets'' or ''Accounts payable and other,'' respectively, on our consolidated statements of financial position. The net regulatory asset or liability balance is comprised of the cumulative over and under recovery adjustments made during the prior calendar year, less any amortizations, and the cumulative over and under recovery adjustments made during current calendar year to date. We track regulatory assets and liabilities by vintage, and our

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

regulatory assets and liabilities are amortized on a straight-line basis over a one-year recovery period. Accordingly, amortization for a net regulatory asset or liability arising from over and under recovery adjustments related to any given calendar year does not begin until January of the following year.

Revenue Recognition and the Estimation of Revenues and Commodity Costs

Liquids

In our Liquids segment, we generally do not own the crude oil and liquid petroleum that we transport or store, and therefore, we do not assume significant direct commodity price risk. Revenues of our Liquids segment are primarily derived from three sources: interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC, ship-or-pay agreements and contract storage revenues related to our crude oil storage assets.

The tariffs established for our interstate pipelines specify the amounts to be paid by shippers for transportation services we provide between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. We recognize revenue upon delivery of products to our customers, when pricing is determinable and collectability is reasonably assured.

Some long-term ship-or-pay contracts also contain make-up-rights, which are granted 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.

We recognize contract storage revenues based on contractual terms under which customers pay for the option to use available storage capacity and/or a fee based on storage volumes. We recognize revenues as storage services are rendered, when pricing is determinable and collectability is reasonably assured.

Revenues for our Liquids segment are all recorded in ''Transportation and other services'' and ''Transportation and other services — affiliate'' on our Consolidated Statements of Income.

Natural Gas

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 contractual arrangements:

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 the services are performed. 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. Consequently, we recognize revenue for reservation fees ratably over the period in which capacity is reserved. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transportation services. Revenues from fee-based arrangements for our Natural Gas segment are recorded in ''Transportation and other services'' and ''Transportation and other services — affiliate'' on our Consolidated Statements of Income.

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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

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 sales proceeds related to natural gas and NGLs we process. The processed products include residue natural gas, NGLs, condensate and sulfur, which we can sell at market prices and retain a percentage of 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. Ownership of the residue natural gas remaining after the extraction of NGLs resides with the customer. 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 where 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. Our commodity cash flows for 2016 are hedged greater than 90%. Due to this unhedged commodity price exposure, our gross margin, representing commodity sales less commodity costs, 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.

Marketing

Marketing revenues are derived from providing supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines, as well as other interconnected pipeline systems. Natural gas marketing services are primarily provided to provide other services valued by our customers. In general, natural gas and NGLs we purchase and sell are priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated revenues result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At the request of some customers, we will enter into long-term fixed price purchase or sales contracts with our customers and usually will enter into offsetting positions under the same or similar terms. We recognize revenues upon delivery of natural gas and NGLs to our customers, when services are rendered, pricing is determinable and collectability is reasonably assured. Marketing revenues for our Natural Gas

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

segment are recorded in ‘‘Commodity sales’’ and ‘‘Commodity sales — affiliate’’ on our Consolidated Statements of Income. The related cost of natural gas and natural gas liquids sold is recorded in ‘‘Commodity costs’’ and ‘‘Commodity costs — affiliate.’’

Estimation of Revenue and Commodity Costs

In order to permit the timely preparation of our consolidated financial statements, for our Natural Gas segment, we estimate our current month revenue and commodity costs. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data before our preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and commodity costs based on the best available volume and price data for natural gas delivered and received, along with an adjustment 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 commodity costs for each of the years ended December 31, 2015, 2014 and 2013. 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 stability of our processes.

In addition, we estimate current month revenues in our Liquids segment. We record an estimate each month for our operating revenues based on the best available volume and rate data for crude oil delivered, along with an adjustment 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 for the years ended December 31, 2015, 2014 and 2013. 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 stability 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 liquid hydrocarbons and natural gas. Upon disposition, product inventory is recorded to ‘‘Commodity costs’’ at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

Oil Measurement Adjustments

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum operations. The three types of oil measurement adjustments that routinely occur on our systems include:

- Physical, which result from evaporation, shrinkage, differences in measurement (including sediment and water measurement) between receipt and delivery locations and other operational conditions;
- Degradation, resulting from mixing at the interface within our pipeline systems or terminal and storage facilities between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- Revaluation, which are a function of crude oil prices, the level of our carriers' inventory and the inventory positions of customers.

Quantifying oil measurement adjustments are difficult because: (1) physical measurements of volumes are not practical, as products continuously move through our pipelines, which are primarily located underground; (2) the extensive length of our pipeline systems; and (3) the numerous grades and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our systems and associated oil measurement adjustments. Material changes in our assumptions may result in revisions to our oil measurement estimates in the period determined. Oil measurement adjustments are included within the ''Operating and administrative'' line item of our Consolidated Statements of Income.

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'' or ''Accrued purchases'' on our consolidated statements of financial position using the posted index prices, which approximate market rates, or our weighted average commodity costs.

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 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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

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. If the sum of the undiscounted future cash flows exceeds the carrying amount of the asset, we recognize an impairment loss in the amount of the excess carrying amount of the asset over its fair value. Fair value is 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 Intangible Assets

Our intangible assets primarily consist of natural gas supply opportunities, customer contracts, and other intangible assets that will benefit our operations, such as software and contributions in aid of construction. 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 intangible assets, we compare the carrying value to the undiscounted future cash flows we expect the intangible assets or the underlying assets to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangible assets, we write the intangible assets down to their fair value.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding commodity costs of natural gas we purchase for processing. 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 record all derivative financial instruments at fair market value in our consolidated statements of financial position. 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

For those instruments that qualify for hedge accounting, 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 are not designated for hedge accounting in our consolidated statements of income as follows:

- Natural Gas segment commodity-based derivatives — ''Commodity Costs'' and ''Commodity sales''
- Liquids segment commodity-based derivatives — ''Transportation and other services'' and ''Power''
- Corporate interest rate derivatives — ''Interest expense''

Qualified Hedges

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 AOCI, a component of ''Partners' capital'' in our consolidated statements of financial position, 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 ''Commodity costs'' for commodity hedges and ''Interest expense'' for interest rate hedges in our consolidated statements of income 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.

Historically, our preference has been 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. Although we retain the ability to designate commodity hedges for cash flow hedge accounting, as of December 31, 2015, we have no remaining commodity hedges that are designated. Designated interest rate derivative financial instruments continue to be reported in AOCI. 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.

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 Enbridge Management 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.

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.

Non-Qualified Hedges

Many of our commodity derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance and prior to December 31, 2015 were designated as cash flow hedges. However, we have transaction types associated with our commodity derivative financial instruments 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 ''Commodity costs,'' ''Commodity sales,'' ''Transportation and other

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

services,'' ''Power'' or ''Interest expense'' 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. Although we retain the ability to designate commodity hedges for cash flow accounting, as of December 31, 2015, we have no remaining commodity hedges that are designated. Designated interest rate derivative financial instruments continue to be reported in AOCI. As such, all commodity hedges are marked-to-market with the changes in fair value recorded in earnings each period.

The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

- **Transportation** — In our Natural Gas segment, 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 Natural Gas segment, we use derivative financial instruments (i.e., natural gas, crude oil and NGL swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas, crude oil and NGLs and the withdrawal price at which these commodities are 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, crude oil and NGLs injected and the price received upon withdrawal of these commodities 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 these commodities, 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 commodities 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 commodity is sold from storage. As a result, derivative financial instruments associated with our storage activities can create volatility in our earnings due to fluctuations in commodity prices until the underlying transactions are settled or offset. After the third quarter of 2015, we no longer have storage hedges associated with natural gas.

- **Condensate, Natural Gas and NGL Options** — In our Natural Gas segment, we use options to hedge the forecasted commodity exposure of our condensate, 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 condensate, NGLs and natural gas until the underlying transactions are settled.

- **Optional Natural Gas Processing Volumes** — In our Natural Gas segment, 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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

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 and Crude Oil Forward Contracts** — In our Natural Gas segment, we use forward contracts to fix the price of NGLs and crude oil we purchase and to fix the price of NGLs and crude oil that we sell to meet the demands of our customers that sell and purchase NGLs and crude oil. A subgroup of physical NGL and physical crude oil 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 change in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL and crude oil prices until the forward contracts are settled.
- **Natural Gas Forward Contracts** — In our Natural Gas segment, we use forward contracts to sell natural gas to our customers. A subgroup of physical natural gas contracts qualify for the NPNS scope exception. All other forward contracts are being marked-to-market each period with the change 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. After the third quarter of 2015, there were no material natural gas forward contracts remaining.
- **Crude Oil Contracts** — In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.
- **Power Purchase Agreements** — In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure. As a result, our operating income is subject to additional volatility associated with changes in the fair value of these agreements due to fluctuations in forward power prices.

Except for physical power, 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 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. Relating to the power purchase agreements, commodity power purchases are immediately consumed as part of pipeline operations and are subsequently recorded as actual power expenses each period.

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 the expected price we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

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 include in this category 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. This category includes both 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.

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust on a recurring basis 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, or the "market approach," to value substantially all of our derivative instruments.

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.

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. Actively traded external market quotes, data from pricing services and published indices are also used to value our derivative instruments. We may use these inputs along with internally developed methodologies that result in our best estimates of fair value.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

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 franchise tax laws by the State of Texas that apply to entities organized as partnerships. This tax is computed on our modified gross margin and we have determined the tax to be an income tax as set forth in authoritative accounting literature.

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.

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. We recognize 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.

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 ''Environmental liabilities'' and ''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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – (continued)

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.

3. NET INCOME PER LIMITED PARTNER UNIT

We allocate our net income among our Series 1 Preferred Units, or Preferred Units, our General Partner interest, and our limited partner units using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income attributable to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We allocate our net income to our limited partners owning Class D units and Class E units equal to the distributions that they receive. We also allocate any earnings in excess of distributions to our General Partner and limited partners owning Class A and B common units and i-units utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners owning Class A and B common units and i-units based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement. We allocate distributions to the General Partner and limited partners based upon the distribution rates and percentages set forth in the following table:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner and IDUs[1]	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.5435	2%	98%
Target Distribution	> $0.5435	25%	75%

(1) For distributions in excess of the Minimum Quarterly Distribution, this percentage includes both the General Partner's distributions of 2% and the distribution to the Incentive Distribution Unit holder, a wholly-owned subsidiary of our General Partner.

Equity Restructuring Transaction

On July 1, 2014, we entered into an equity restructuring transaction, or Equity Restructuring, with the General Partner in which the General Partner irrevocably waived its right to receive cash distributions and allocations of items of income, gain, deduction, and loss in excess of 2% in respect of its general partner interest in the incentive distribution rights, or Previous IDRs, in exchange for the issuance to a wholly-owned subsidiary of the General Partner of (i) 66.1 million units of a new class of limited partner interests designated as Class D units, and (ii) 1,000 units of a new class of limited partner interests designated as Incentive Distribution Units, or IDUs. For more information, refer to Note 11. *Partners' Capital*. Prior to this transaction, we allocated distributions to the General Partner and limited partners as follows:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.295	2%	98%
First Target Distribution	> $0.295 to $0.35	15%	85%
Second Target Distribution	> $0.35 to $0.495	25%	75%
Over Second Target Distribution	In excess of $0.495	50%	50%

3. NET INCOME PER LIMITED PARTNER UNIT – (continued)

Alberta Clipper Drop Down

On January 2, 2015, we completed a transaction to acquire from our General Partner the remaining 66.7% interest in the U.S. portion of the Alberta Clipper Pipeline. The consideration consisted of issuance to the General Partner of 18,114,975 units of a new class of limited partner interests designated as Class E units. For more information, refer to Note 11. *Partners' Capital*.

We determined basic and diluted net income (loss) per common unit and i-unit as follows:

	For the year ended December 31,		
	2015	2014	2013
	(in millions, except per unit amounts)		
Net income	$ 454.3	$ 740.0	$ 160.4
Less Net income attributable to:			
Noncontrolling interest	(221.1)	(263.3)	(88.3)
Series 1 preferred unit distributions	(90.0)	(90.0)	(58.2)
Accretion of discount on Series 1 preferred units	(11.2)	(14.9)	(9.2)
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	132.0	371.8	4.7
Less distributions:			
Incentive distributions	(18.9)	(39.1)	(129.9)
Distributed earnings attributed to our General Partner	(20.5)	(17.3)	(14.2)
Distributed earnings attributed to Class D and Class E units	(195.3)	(107.5)	—
Total distributed earnings to our General Partner, Class D and Class E units and IDUs	(234.7)	(163.9)	(144.1)
Total distributed earnings attributed to our common units and i-units	(791.4)	(731.0)	(695.6)
Total distributed earnings	(1,026.1)	(894.9)	(839.7)
Overdistributed earnings	$ (894.1)	$(523.1)	$(835.0)
Weighted average common units and i-units outstanding	339.1	328.2	316.2
Basic and diluted earnings per unit:			
Distributed earnings per common unit and i-unit[1]	$ 2.33	$ 2.23	$ 2.20
Overdistributed earnings per common unit and i-unit[2]	(2.58)	(1.56)	(2.59)
Net income (loss) per common unit and i-unit (basic and diluted)[3]	$ (0.25)	$ 0.67	$ (0.39)

(1) Represents the total distributed earnings to common units and i-units divided by the weighted average number of common units and i-units outstanding for the period.

(2) Represents the common units' and i-unit's share (98%) of distributions in excess of earnings divided by the weighted average number of common units and i-units outstanding for the period and overdistributed earnings allocated to the common units and i-units based on the distribution waterfall that is outlined in our partnership agreement.

(3) For the years ended December 31, 2015, 2014 and 2013, 43,201,310 anti-dilutive Preferred Units were excluded from the if-converted method of calculating diluted earnings per unit. For the years ended December 31, 2015 and 2014, 66,100,000 anti-dilutive Class D units were excluded from the if-converted method of calculating diluted earnings per unit. For the year ended December 31, 2015, 18,114,975 anti-dilutive Class E units were excluded from the if-converted method of calculating diluted earnings per unit.

4. ACQUISITIONS

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

On February 27, 2015, MEP acquired the midstream business of New Gulf Resources, LLC, or NGR, in Leon, Madison and Grimes Counties, Texas. The acquisition consisted of a natural gas gathering system that is in

4. ACQUISITIONS – (continued)

operation. This acquisition strengthened MEP's position into the Eaglebine play, and will continue to allow them to offer gathering and processing services while leveraging assets on their existing footprint.

MEP acquired NGR's midstream business for $85.0 million in cash and a contingent future payment of up to $17.0 million. Of the $85.0 million purchase price, $20.0 million was placed into escrow, pending the resolution of a legal matter and NGR's completion of additional wells connecting to our system. Since the acquisition date, MEP has released $8.0 million from escrow and paid it to NGR. Of the remaining $12.0 million in escrow, $6.0 million and $6.0 million have been classified as ''Restricted cash'' and ''Other assets, net'', respectively, in our consolidated statements of financial position as of December 31, 2015.

If NGR is able to deliver volumes into the system at certain tiered volume levels over a five-year period, MEP will be obligated to make future tiered payments up to $17.0 million. This could result in a maximum total purchase price of $102.0 million. The potential payment is considered contingent consideration. At the acquisition date, the fair value of this contingent consideration, using a probability-weighted discounted cash flow model was $2.3 million. The contingent consideration is remeasured on a fair value basis each quarter until the performance bonus is paid or expires. At December 31, 2015, contingent consideration of $2.5 million, which includes $0.2 million in accretion, is included in ''Other long-term liabilities'' in our consolidated statements of financial position.

Funding for the acquisition was provided by us and MEP, based on our proportionate ownership percentages in Midcoast Operating, L.P., or Midcoast Operating, at the time of acquisition, which was 48.4% and 51.6%, respectively. This business is part of our Natural Gas segment.

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 $21.5 million and $17.9 million at December 31, 2015 and 2014, respectively, are included in ''Accounts payable and other'' on our consolidated statements of financial position. At December 31, 2014, we reclassified book overdrafts of $40.0 million to ''Accounts payable and other'' on our consolidated statement of financial position. We did not have any book overdrafts at December 31, 2015.

6. INVENTORY

Our inventory is comprised of the following:

	December 31, 2015	December 31, 2014
	(in millions)	
Materials and supplies	$ 2.2	$ 2.2
Crude oil inventory	1.6	13.2
Natural gas and NGL inventory	31.3	78.8
	$35.1	$94.2

''Commodity costs'' on our consolidated statements of income include charges totaling $5.8 million, $11.4 million and $3.4 million for the years ended December 31, 2015, 2014 and 2013, 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, 2015	December 31, 2014
		(in millions)	
Land	–	$ 62.9	$ 44.2
Rights-of-way	1.80% – 13.00%	952.5	851.8
Pipelines	1.79% – 13.00%	10,376.3	9,585.4
Pumping equipment, buildings and tanks[1]	1.48% – 13.00%	4,232.3	3,261.8
Compressors, meters and other operating equipment	1.80% – 20.00%	2,147.6	2,072.7
Vehicles, office furniture and equipment[1]	1.33% – 33.33%	280.0	278.9
Processing and treating plants	2.21% – 4.00%	627.8	516.0
Construction in progress		1,968.8	1,857.1
Total property, plant and equipment		20,648.2	18,467.9
Accumulated depreciation		(3,235.8)	(2,775.2)
Property, plant and equipment, net		$17,412.4	$15,692.7

[1] During the second quarter 2015, management reclassified $135.0 million related to rail facilities from ''Vehicles, office furniture and equipment'' to ''Pumping equipment, buildings, and tanks'' to better reflect the way in which these assets are analyzed. This change has been retrospectively adjusted for all periods presented.

During the year ended December 31, 2015, due to contracts that have not been renewed subsequent to 2016, we recorded a non-cash impairment loss of $62.5 million to write off the remaining carrying value of our Berthold rail facility, which is included in ''Asset impairment'' on our consolidated statements of income.

On July 31, 2015, MEP sold its non-core Tinsley crude oil pipeline, storage facilities, and docks and its non-core Louisiana propylene pipeline for $1.3 million. These assets are part of our Natural Gas segment and had a combined carrying value of $4.5 million at the date of sale. The loss on disposal of $3.2 million for the year December 31, 2015, is included in ''Operating and administrative'' expense on our consolidated statement of income. In addition, for each of the years ended December 31, 2015 and 2014, we recorded $12.3 million and $15.6 million, respectively, in non-cash impairment charges on these assets, which are included in ''Asset impairment'' on our consolidated statements of income.

During the year ended December 31, 2014, we retired components of our pre-replacement Line 6B assets, including the related asset retirement costs, in the amount of $282.5 million. Consistent with the group method of depreciation, we charged the retirement of these components to accumulated depreciation.

We do not have any assets that are legally restricted for purposes of settling our AROs at December 31, 2015 and 2014. The following is a reconciliation of the beginning and ending aggregate carrying amounts of our ARO liabilities for each of the years ended December 31, 2015 and 2014:

	2015	2014
	(in millions)	
Balance at beginning of period	$ 96.8	$ 3.4
Revisions in estimates	14.1	13.2
Additions	—	100.7
Accretion expense	1.5	1.1
Liabilities settled	(8.8)	(21.6)
Balance at end of period	$103.6	$ 96.8

For the year ended December 31, 2014, we recorded $67.2 million and $46.7 million in AROs, including revisions in estimates, related to the pre-replacement of Lines 3 and 6B, respectively. We did not record any additional AROs for the years ended December 31, 2015 and 2013.

8. GOODWILL

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. Our goodwill originated from acquisitions that are fully associated with our natural gas business. For each of the years ended December 31, 2014 and 2013, the carrying amount of goodwill was $246.7 million.

We test goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. During May 2015, due to adverse market conditions facing our business, we learned from producers that reductions in drilling will be sustained and prolonged due to continued low prices for natural gas and NGLs. As a result, we determined that the impact on our forecasted operating profits and cash flows for the natural gas reporting unit for the next five years would be significantly reduced from our prior forecasts.

During the second quarter of 2015, we performed the first step of our goodwill impairment analysis and determined that the carrying value of the natural gas reporting unit exceeded fair value. We completed the second step of the goodwill impairment analysis comparing the implied fair value of the reporting unit to the carrying amount of that goodwill, using amounts as of June 30, 2015, and determined that goodwill was completely impaired in the amount of $246.7 million. The impairment charge is presented as ''Goodwill impairment'' on our consolidated statement of income for the year ended December 31, 2015. We did not record any goodwill impairments during the years ended December 31, 2014 and 2013.

We measure the fair value of our reporting units 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. Our estimate of fair value required us to use significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of our natural gas reporting unit.

9. INTANGIBLE ASSETS

The following table provides the estimated useful life, gross carrying value, accumulated amortization and net carrying value for each of our major classes of intangible assets:

		December 31, 2015			December 31, 2014		
	Estimated Useful Life	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
				(in millions)			
Natural gas supply opportunities	15 – 30 years	$324.1	$ (81.8)	$242.3	$291.0	$(69.7)	$221.3
Other intangible assets	3 – 25 years	102.2	(64.5)	37.7	49.2	(15.7)	33.5
Total intangible assets		$426.3	$(146.3)	$280.0	$340.2	$(85.4)	$254.8

Intangible assets primarily include natural gas supply opportunities, which are 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. These natural gas supply opportunities primarily consist of dedicated acreage, whereby any prospective producers commencing drilling in areas served by our assets would be required to connect to our systems. Natural gas supply opportunities also include dedicated acreage and long-term annual volume commitments with NGR as a result of our acquisition of its midstream operations on February 27, 2015. The related intangible assets were valued at $32.2 million at the time of the acquisition. For further details regarding the NGR acquisition, see Note 4. *Acquisitions*.

Other intangible assets primarily include software, customer contracts and contributions in aid of construction, or CIACs. These other intangible assets have estimated useful lives that range as short as three years for software to as long as 25 years for CIACs.

9. INTANGIBLE ASSETS – (continued)

For the years ended December 31, 2015, 2014 and 2013, our amortization expense related to intangible assets totaled $22.2 million, $15.5 million and 16.3 million, respectively. The following table presents our forecast of amortization expense associated with existing intangible assets for the years indicated as follows in millions:

2016	2017	2018	2019	2020
$ 22.3	$16.8	$14.3	$14.3	$14.2

10. DEBT

The following table presents the primary components of our outstanding indebtedness with third parties and the weighted average interest rates associated with each component as of December 31, 2015, before the effect of our interest rate hedging activities. Our indebtedness with related parties is discussed in Note 12. *Related Party Transactions*.

	Interest Rate	December 31, 2015	December 31, 2014
		(in millions)	
EEP debt obligations:			
Commercial Paper[1]	1.217%	$ 326.1	$ 612.3
Credit Facilities due 2017 – 2020	1.530%	1,110.0	1,160.0
Senior Notes due December 2016	5.875%	300.0	300.0
Senior Notes due April 2018	6.500%	400.0	400.0
Senior Notes due March 2019	9.875%	500.0	500.0
Senior Notes due October 2020	4.375%	500.0	—
Senior Notes due March 2020	5.200%	500.0	500.0
Senior Notes due September 2021	4.200%	600.0	600.0
Senior Notes due October 2025	5.875%	500.0	—
Senior Notes due June 2033	5.950%	200.0	200.0
Senior Notes due December 2034	6.300%	100.0	100.0
Senior Notes due April 2038	7.500%	400.0	400.0
Senior Notes due September 2040	5.500%	550.0	550.0
Senior Notes due October 2045	7.375%	600.0	—
Junior subordinated notes due 2067	8.050%	400.0	400.0
OLP debt obligations:			
Senior Notes due October 2018	7.000%	100.0	100.0
Senior Notes due October 2028	7.125%	100.0	100.0
MEP debt obligations:			
MEP Credit Agreement	3.700%	490.0	360.0
MEP Series A Senior Notes due September 2019	3.560%	75.0	75.0
MEP Series B Senior Notes due September 2021	4.040%	175.0	175.0
MEP Series C Senior Notes due September 2024	4.420%	150.0	150.0
Total Principal of Debt Obligations		8,076.1	6,682.3
Other:			
Unamortized Discount		(6.2)	(7.1)
Current maturities of long-term debt	5.875%	(300.0)	—
Total Long Term Debt		$7,769.9	$6,675.2

(1) Individual issuances of commercial paper generally mature in 90 days or less, but are supported by our Credit Facilities and are therefore considered long-term debt.

10. DEBT – (continued)

Interest Cost

Our interest cost for the years ended December 31, 2015, 2014 and 2013 is comprised of the following:

	For the year ended December 31,		
	2015	2014	2013
		(in millions)	
Interest cost incurred	$362.9	$448.5	$372.1
Less: Interest capitalized	40.9	45.3	51.7
Interest expense	$322.0	$403.2	$320.4

Maturities of Third Party Debt

The scheduled maturities of outstanding third-party debt, excluding any discounts at December 31, 2015, are summarized as follows in millions:

2016	$ 300.0
2017	826.1
2018	990.0
2019	575.0
2020	1,610.0
Thereafter	3,775.0
Total	$8,076.1

Credit Facilities

Our multi-year senior unsecured revolving credit facility, which we refer to as the Credit Facility, permits aggregate borrowings of up to, at any one time outstanding, $1.975 billion, a letter of credit subfacility and a swing line subfacility. The Credit Facility matures September 26, 2020; however, $175.0 million of commitments will expire on the original maturity date of September 26, 2018.

We also have a 364-day revolving credit agreement, which we refer to as the 364-Day Credit Facility. On July 2, 2015, we amended our 364-Day Credit Facility to extend the revolving credit termination date from July 3, 2015 to July 1, 2016. During July and August of 2015, we further amended the 364-Day Credit Facility, to decrease the aggregate commitments from $650.0 million to $625.0 million: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion, and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods.

We refer to these credit facilities together as the Credit Facilities. At December 31, 2015, the Credit Facilities provide an aggregate bank credit amount of approximately $2.6 billion, which we use to fund our general activities and working capital needs.

Under our Credit Facilities, we had net repayments of approximately $50.0 million during the twelve month period ended December 31, 2015, which includes gross borrowings of $15.6 billion and gross repayments of $15.7 billion.

LIBOR rate borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the twelve months ended December 31, 2015 and 2014, we had LIBOR rate outstanding borrowings of $1.2 billion and 1.2 billion, respectively, under our Credit Facilities and no base rate borrowings.

10. DEBT – (continued)

The Credit Facilities contain, among other affirmative and negative covenants, certain financial covenants. A failure to comply with these covenants could result in an event of default under the Credit Facilities, which would prohibit us from declaring or making distributions to our unitholders and would permit acceleration of, and termination of our access to, our indebtedness under the Credit Facilities, and may cause acceleration of our outstanding senior notes. Although we expect to be able to comply with these covenants under each of our Credit Facilities, there can be no assurance that in the future we will be able to do so or that our lenders will be willing to waive such non-compliance or further amend such covenants. As of December 31, 2015, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

Our Credit Facilities previously were amended to (1) exclude up to $650.0 million of the costs associated with the remediation of the area affected by the crude oil releases on Lines 6A and 6B from the Earnings before interest, taxes, depreciation and amortization, or EBITDA, component of the consolidated leverage ratio covenant in each of our Credit Facilities and (2) with respect to the quarterly covenant compliance testing, from the definition of consolidated net income component of the consolidated leverage ratio covenant, accrued but unpaid costs, expenses, fines, and penalties occurring after September 30, 2013, related to the remediation of the area affected by the crude oil releases on Lines 6A and 6B.

On February 3, 2014, we entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200.0 million. On September 9, 2014, the amount was increased to $220.0 million, and on December 16, 2015, the amount was decreased to $175.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank's sole discretion, we view this arrangement as liquidity enhancement as it allows us to potentially reduce its reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support its hedging activities.

On March 9, 2015, we entered into an unsecured revolving 364-day credit agreement, which we refer to as the EUS 364-day Credit Facility, with Enbridge (U.S.) Inc., or EUS. On November 16, 2015, we received a commitment reduction notice from EUS with respect to the credit agreement with EUS that previously permitted aggregate borrowing of up to, at any one time outstanding, $750.0 million. EUS has elected to reduce its commitment to zero following the Partnership's offering of $1.6 billion of debt securities in October of 2015. See Note 12. Related Party Transactions for further details.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At December 31, 2015, we had approximately $326.1 million in principal amount of commercial paper outstanding at a weighted average interest rate of 1.22%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net repayments of approximately $286.1 million during the twelve month period ended December 31, 2015, which includes gross borrowings of $12.0 billion and gross repayments of $12.3 billion. At December 31, 2014, we had $612.3 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.50%, excluding the effect of our interest rate hedging activities. Our policy is that the commercial paper we can issue is limited by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our Credit Facilities. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

10. DEBT – (continued)

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at December 31, 2015, we had approximately $1.0 billion available to us under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under our Credit Facilities	$2,600.0
Less: Amounts outstanding under our Credit Facilities	1,110.0
Principal amount of commercial paper outstanding	326.1
Letters of credit outstanding	121.7
Total amount available at December 31, 2015	$1,042.2

Senior Notes

On October 6, 2015, we closed a public offering of $1.6 billion of senior unsecured notes, comprised of $500 million aggregate principal amount of notes due October 15, 2020, $500 million aggregate principal amount of senior notes due October 15, 2025 and $600 million aggregate principal amount of notes due October 15, 2045 for net proceeds of approximately $1.575 billion after deducting underwriting discounts and commissions and offering expenses. In connection with the offering, we paid $314.7 million to settle certain pre-issuance hedges. Of that amount, a loss of $76.4 million was recognized in interest expense from ineffectiveness. The remaining loss of $238.3 million recorded in accumulated other comprehensive income will be amortized as interest expense over a period of eight to ten years. As the pre-issuance hedge was designed to hedge the interest rate risk associated with the new debt, we have elected to classify the $238.3 million effective portion of the cash settlement, along with the $76.4 million of ineffectiveness included in interest expense, as "Net cash provided by operating activities" in the consolidated statement of cash flows.

Our senior notes represent unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes have varying maturities and terms and are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $200.0 million of senior notes issued by the OLP. The borrowings under our senior notes are non-recourse to our General Partner and Enbridge Management. We either pay or accrue interest semi-annually on our senior notes.

The OLP, our operating subsidiary that owns the Lakehead system, has $200.0 million of senior notes outstanding representing unsecured obligations that are structurally senior to our senior notes. The OLP Notes consist of $100.0 million of 7.000% senior notes due 2018 and $100.0 million of 7.125% senior notes due 2028. All of the OLP Notes pay interest semi-annually.

The OLP Notes do not contain any covenants restricting us from issuing additional indebtedness by the OLP. The OLP Notes are subject to make-whole redemption rights and were issued under an indenture, referred to as the OLP Indenture, containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets, except in accordance with the OLP Indenture. We were in compliance with these covenants at December 31, 2015.

Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, payable semi-annually in arrears on April 1 and October 1 of each year until October 1, 2017. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but

10. DEBT – (continued)

not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017, and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047, or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part, prior to October 1, 2017, for a "make-whole" redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017, in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

MEP Credit Agreement

On November 13, 2013, in connection with the closing of the Offering, MEP, Midcoast Operating, and their material domestic subsidiaries, entered into a Credit Agreement, which we refer to as the MEP Credit Agreement, by and among MEP, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, MEP's material subsidiaries party thereto as guarantors.

The MEP 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, MEP may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility matures in two years, subject to four one-year requests for extensions.

On September 3, 2015, MEP amended the MEP Credit Agreement and decreased the aggregate commitments to $810.0 million. On September 3, 2015, MEP further amended the MEP Credit Agreement to extend the maturity date from September 30, 2017 to September 30, 2018; however, $140.0 million of commitments will expire on the original maturity date of November 13, 2016, and an additional $25.0 million of commitments will expire on

10. DEBT – (continued)

September 30, 2017. On September 30, 2014, MEP entered into an amended and restated subordination agreement by and among MEP, Midcoast Operating, the other parties from time to time party thereto and us to accommodate the subordination agreement entered into in connection with the Purchase Agreement, described below under ''MEP Private Debt Issuance.''

Loans under the MEP Credit Agreement accrue interest at a per annum rate by reference, at MEP's 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. At December 31, 2015, MEP had $490.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 3.7%. Under the Credit Agreement, MEP had net borrowings of approximately $130.0 million during the twelve month period ended December 31, 2015, which includes gross borrowings of $6.1 billion and gross repayments of $6.0 billion.

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 MEP 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 MEP's domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the MEP Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The MEP 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 MEP Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

The MEP Credit Agreement also requires compliance with two financial covenants. MEP must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio) of MEP 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. MEP 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 December 31, 2015, MEP was in compliance with the terms of their financial covenants.

MEP Private Debt Issuance

On September 30, 2014, MEP completed a private debt offering of $400.0 million of notes consisting of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. MEP received approximately $398.1 million in net proceeds, which were used to repay outstanding indebtedness and for other general partnership purposes. Using a portion of the net proceeds, MEP settled two interest rate swaps for a net payment of $0.9 million on September 30, 2014, which will be amortized to interest expense over the original five year hedge term.

The Notes were issued pursuant to a Note Purchase Agreement, or the Purchase Agreement, between MEP and the purchasers named therein. The Notes and all other obligations under the Purchase Agreement are unconditionally guaranteed by each of MEP's domestic material subsidiaries pursuant to a guaranty agreement. Until such time as MEP obtains an investment grade rating from either Moody's or S&P and upon certain trigger events, MEP and the guarantors will grant liens in their assets (subject to certain excluded assets) to secure the obligations under the Notes. There are currently no liens associated with the Notes.

10. DEBT – (continued)

Additionally, the Purchase Agreement contains various covenants and restrictive provisions which limit the ability of MEP and its subsidiaries to incur certain liens or permit such liens to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests, incur or guarantee additional debt, repay subordinated debt or certain debt owed to affiliates prior to maturity, alter MEP's lines of business, and enter into certain types of transactions with affiliates or subsidiaries that MEP is permitted to designate as unrestricted subsidiaries.

The Purchase Agreement contains events of default, indemnities, and covenants customary for transactions of this nature. These covenants and restrictive provisions are subject to exceptions and qualifications set forth in the Purchase Agreement. At such time as MEP obtains an investment grade rating from either Moody's or S&P, the obligation to provide security in certain circumstances will no longer be applicable to us or the guarantors and certain restrictions on prepayments of certain subordinated and affiliate will become less restricted.

The Purchase Agreement also requires compliance with two financial covenants. MEP must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio) 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. MEP 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. At December 31, 2015, MEP was in compliance with the terms of its financial covenants under the Purchase Agreement.

The Notes are prepayable at MEP's option, in whole or in part, provided that any such prepayment may incur a ''make-whole'' premium as specified in the Purchase Agreement. MEP must offer to prepay the notes upon the occurrence of any change of control. Under the Purchase Agreement, a change of control occurs if we or Enbridge ceases to control, directly or indirectly, MEP's general partner. In addition, MEP must offer to prepay the Notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets.

In connection with MEP's entry into the Purchase Agreement, MEP, along with the guarantors and us, entered into a subordination agreement in which we agreed to subordinate our right to payment on obligations owed by Midcoast Operating under the Financial Support Agreement entered into by and between Midcoast Operating and us on November 13, 2013, and liens, if secured, to the rights of the holders under the Purchase Agreement, subject to the terms and conditions of the subordination agreement in favor and for the benefit of the holders of the Notes.

Fair Value of Debt Obligations

The carrying amounts of our outstanding commercial paper, borrowings under our Credit Facilities, and the MEP Credit Agreement approximate their fair values at December 31, 2015 and 2014, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The fair value of our outstanding commercial paper and borrowings under our Credit Facilities and the MEP Credit Agreement are included with our long-term debt obligations above since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

The approximate fair value of our fixed-rate debt obligations was $5.9 billion and $5.1 billion at December 31, 2015 and 2014, respectively. We determined the approximate fair value 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. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding. The fair value of our long-term debt obligations is categorized as Level 2 within the fair value hierarchy.

11. PARTNERS' CAPITAL

Our capital accounts are comprised of a 2% general partner interest and 98% limited partner interests. Our limited partner interests at December 31, 2015, include Series 1 preferred units, Class D units, Class E units, Class A and Class B common units, i-units and IDUs. We refer to our Class A and Class B common units collectively as common units. Our limited partners have limited rights of ownership as provided for under our partnership agreement and, as discussed below, the right to participate in our distributions. Our General Partner

11. PARTNERS' CAPITAL – (continued)

manages our operations, subject to a delegation of control agreement with Enbridge Management, and participates in our distributions. At December 31, 2015 and 2014, our outstanding ownership interests were as follows:

	2015	2014
Series 1 preferred units	9.9%	10.6%
Class D units owned by our General Partner	13.6%	14.6%
Class E units owned by our General Partner	3.7%	—%
Class A common units owned by the public	44.5%	45.8%
Class A common units owned by our General Partner	9.6%	10.3%
Class B common units owned by our General Partner	1.6%	1.7%
i-units owned by Enbridge Management[1]	15.1%	15.0%
Incentive distribution units owned by our General Partner	—%	—%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

(1) For the years ended December 31, 2015 and 2014, our General Partner owned 11.7% of Enbridge Management, which owns all of our i-units.

Series 1 Preferred Units

In 2013, we issued and sold 48,000,000 Series 1 preferred units, representing limited partner interests in us, or Preferred Units, for aggregate proceeds of approximately $1.2 billion. We used proceeds from the Preferred Unit issuance to repay commercial paper, to finance a portion of our capital expansion program relating to our core liquids and natural gas systems and for general partnership purposes. On July 30, 2015, we amended our limited partnership agreement to extend the deferral of distribution payments, to extend the rate reset pricing date, and to defer the conversion option date, as discussed below. The amendment was accounted for as a modification to the Series 1 Preferred Unit Agreement, as the difference in the fair value of the Preferred Units before and after the modification was insignificant.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset on June 30, 2020, and each subsequent five-year anniversary thereafter. However, these quarterly cash distributions, during the first full twenty quarters ending June 30, 2018, will accrue and accumulate, which we refer to as the Payment Deferral. These amounts will be paid in equal amounts over a twelve-quarter period beginning in the first quarter of 2019. The quarterly cash distribution for the three month period ended June 30, 2013, was prorated from May 8, 2013.

On or after June 1, 2018, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) we use the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies' treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions, including the Payment Deferral.

The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders' and General Partner's capital and a decrease in Preferred Unitholders' capital to reflect the fair value of the Preferred Units at issuance on the our consolidated statement of partners' capital for the year ended December 31, 2013. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013 through the first conversion date, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders' capital.

11. PARTNERS' CAPITAL – (continued)

As discussed above, the Series 1 Preferred Unit Agreement was amended on July 30, 2015 to, among other things, extend the first conversion date of the Preferred Units. As a result, the remaining unamortized beneficial conversion feature after the amendment will be amortized ratably over the extended period through June 30, 2018.

Equity Restructuring Transaction

On July 1, 2014, we entered into an equity restructuring transaction, or Equity Restructuring, with the General Partner in which the General Partner irrevocably waived its right to receive cash distributions and allocations of items of income, gain, deduction, and loss in excess of 2% in respect of its general partner interest in the incentive distribution rights, or Previous IDRs, in exchange for the issuance to a wholly-owned subsidiary of the General Partner of (i) 66.1 million units of a new class of limited partner interests designated as Class D units, and (ii) 1,000 units of a new class of limited partner interests designated as Incentive Distribution Units, or IDUs.

The Class D units entitle the holder thereof to receive quarterly distributions equal to the amount derived by multiplying the number of Class D units outstanding by the distribution rate paid on our common units. The Class D units are convertible on a one-for-one basis into our Class A common units any time after the fifth anniversary of issuance, or July 1, 2019, at the holder's option. We may redeem the Class D units in whole or in part after the 30-year anniversary of issuance, or July 1, 2044, at our option for either a cash amount equal to the notional value per unit, or with newly issued Class A common units with an aggregate market value at redemption equal to 105% of the aggregate notional value of the Class D units being redeemed. The Class D units have a notional value of $31.35 per unit, which was the closing price of our Class A common units on June 17, 2014, and have the same voting rights as the Class A common units. In the event of a liquidation event (or any merger or other extraordinary transaction), the Class D units entitle the holder thereof to a preference in liquidation equal to 20% of the notional value, with such preference being increased by an additional 20% on each anniversary of issuance, resulting in a liquidation preference equal to 100% of the notional value on and after July 1, 2018. The Class D units have a liquidation preference equal to their notional value at July 1, 2014 of $31.35 per unit, which is also the liquidation value of the units.

The IDUs entitle the holder thereof to receive 23% of the incremental distributions we pay in excess of $0.5435 per common unit and Class D unit per quarter. In the event of any decrease in the Class A common unit distribution below the quarterly distribution level of $0.5435 per unit in any quarter during the five years commencing with the fourth quarter of 2014, the distribution we pay on the Class D units will be adjusted to the amount that we would have paid in respect of the Previous IDRs had the Equity Restructuring not occurred. In addition, we reduced the third quarter 2014 distribution on the Class D units so that the aggregate distributions paid in calendar year 2014 with respect to the previous IDRs, the Class D units, and the IDUs did not exceed the distribution that we would have paid in calendar year 2014 in respect to the Previous IDRs had the Equity Restructuring not occurred.

We recorded the Class D units and IDUs at their fair values of $2,480.0 million and $491.7 million, respectively, with the offset being recorded as a reduction to the carrying amounts of the capital accounts of the Class A and Class B common units, the i-units and the general partner on a pro rata basis. We determined the fair values of the Class D units using a market approach based upon the closing price of the Class A common units as of July 1, 2014 adjusted for differences in specific rights granted to the Class D units and other economic factors that would affect the fair value of the Class D units. We determined the fair value of the IDUs using an income approach on the basis of discounted cash flows from expected quarterly distributions.

Alberta Clipper Drop Down

On January 2, 2015, we completed a transaction, or the Drop Down, pursuant to which we acquired the remaining 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline from our General Partner. The consideration consisted of approximately 18,114,975 units of a new class of limited partner interests designated as Class E units issued to the General Partner. The Class E units were issued at a notional value of $38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of our Class A common units as of that date, which was the date on which we and the General Partner entered into a contribution agreement

11. PARTNERS' CAPITAL – (continued)

setting forth the terms of the Drop Down. In addition, we repaid the borrowings outstanding of $306.0 million on the A1 Term Note owed to the General Partner.

The Class E units are entitled to the same distributions as Class A common units held by the public and are convertible into Class A common units on a one-for-one basis at the General Partner's option. The Class E units were not entitled to distributions with respect to the quarter ended December 31, 2014. The Class E units are redeemable at our option after 30 years, if not earlier converted by the General Partner.

The Class E units have a liquidation preference equal to their notional value at December 23, 2014 of $38.31 per unit, which is also the liquidation value of the units. If the aggregate EBITDA attributable to the Series AC interest in the OLP for calendar years 2015 and 2016 is less than $265.9 million, then 1,305,142 of the Class E units will be cancelled by us effective as of June 15, 2017, for no consideration and will no longer be deemed outstanding for any purposes under our partnership agreement.

In addition, during each taxable year during the period from January 1, 2015 through December 31, 2037 in which a majority of the Class E units issued on the closing date of the Drop Down remain outstanding, holders of Class A common units, Class B common units and Class D units (including those held by the General Partner) will be specially allocated items of gross income that would otherwise be allocated to holders of Class E units, to the extent that such an amount of gross income exists, in an annual amount equal to $40.0 million. The annual amount of such allocation will be reduced to $20.0 million for each taxable year beginning after December 31, 2037.

We recorded the Drop Down as an equity transaction. No loss on the acquisition of the remaining ownership interests in Alberta Clipper was recognized in our consolidated statement of income or comprehensive income. We reduced the carrying value of the related ''Noncontrolling interest'' in Alberta Clipper of $403.7 million to zero. In addition, we recorded the Class E units at their fair value of $767.7 million. We determined the fair value of the Class E units using a market approach based upon the closing price of the Class A common units as of January 2, 2015, adjusted for differences in specific rights such as the liquidation preference granted to the Class E units and other economic factors that would affect the fair value of the Class E units.

The difference of $364.0 million between the fair value of the Class E units and the carrying value of the noncontrolling interest in Alberta Clipper was recorded as a reduction to the carrying amounts of the capital accounts of the Class A and Class B common units, the i-units and the General Partner interest on a pro rata basis. The recording of this transaction reduced the carrying values of the Class A and Class B common units below zero. Our partnership agreement requires that such capital account deficits are brought back to zero, or ''cured,'' by additional allocations from the capital accounts of the i-units and General Partner interest on a pro-rata basis. As a result the i-units' and General Partner interest's capital balances were reduced by $46.7 million and $1.0 million, respectively, to cure the deficit balances in the Class A and Class B common units. This initial curing did not impact earnings allocated to either the i-units or the General Partner interest.

Additional Curing

During 2015, in addition to the curing of the Class A and Class B common units resulting from the Drop Down, the carrying amounts for the capital accounts of the Class A and Class B common units were reduced below zero due to distributions to partners in excess of earnings attributable to partners. As a result, the capital balances of the i-units and General Partner interests were reduced by $362.3 million and $30.5 million, respectively, to cure the deficit balances in the Class A and Class B common units.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. In February 2015, we filed with the SEC a new shelf registration statement, or the 2015 Shelf, on Form S-3 that replaced our prior shelf registration statement which expired in December 2014. The 2015 Shelf allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

11. PARTNERS' CAPITAL – (continued)

Issuance of Class A Common Units

The following table presents the net proceeds from our Class A common unit issuances for the year ended December 31, 2015. There were no issuances of Class A common units for the years ended December 31, 2014 and 2013.

2015 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)			
March	8,000,000	$36.70	$288.8	$6.0	$294.8

(1) Net of underwriters' fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

The proceeds from the March 2015 offering were used to fund a portion of our capital expansion projects and for general partnership purposes.

Class B common units

All of our outstanding Class B common units are held by our General Partner and have rights similar to our Class A common units except that they are not currently eligible for trading on the NYSE.

i-units

The i-units are a separate class of our limited partner interests, all of which are owned by Enbridge Management and are not publicly traded.

Enbridge Management, as the owner of our i-units, votes together with the holders of the common units as a single class. However, the i-units vote separately as a class on the following matters:

- Any proposed action that would cause us to be treated as a corporation for United States federal income tax purposes;
- Amendments to our partnership agreement that would have a material adverse effect on the holder of our i-units, unless, under our partnership agreement, the amendment could be made by our General Partner without a vote of holders of any class of units;
- The removal of our General Partner and the election of a successor general partner; and
- The transfer by our General Partner of its general partner interest to a non-affiliated person that requires a vote of holders of units under our partnership agreement and the admission of that person as a general partner.

In all cases, Enbridge Management will vote or refrain from voting its i-units in the same manner that owners of Enbridge Management's shares vote or refrain from voting their shares. Furthermore, under the terms of our partnership agreement, we agree that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as the i-units.

Investments

In March 2013, Enbridge Management completed a public offering of 10,350,000 Listed Shares, representing limited liability company interests with limited voting rights, at a price to the underwriters of $26.44 per Listed Share. Enbridge Management received net proceeds of $272.9 million, which were subsequently invested in a number of our i-units equal to the number of Listed Shares sold in the offering. We used the proceeds from our issuance of i-units to Enbridge Management to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

11. PARTNERS' CAPITAL – (continued)

In September 2013, Enbridge Management completed a public offering of 8,424,686 Listed Shares, representing limited liability company interests with limited voting rights, at a price to the underwriters of $28.02 per Listed Share. Enbridge Management received net proceeds of $235.6 million, which were subsequently invested in a number of our i-units equal to the number of Listed Shares sold in the offering. We used the proceeds from our issuance of i-units to Enbridge Management to repay commercial paper, finance a portion of our capital expansion program relating to our core liquids and natural gas systems and for general corporate purposes.

Distributions

Our partnership agreement requires us to distribute 100% of our ''available cash'', which is generally defined in our partnership agreement as the sum of all cash receipts plus reductions in cash reserves established in prior quarters less cash disbursements and additions to cash reserves in that calendar quarter. Enbridge Management, as delegate of our General Partner under the delegation of control agreement, computes the amount of our ''available cash.'' Typically, our General Partner and owners of our common units will receive distributions in cash. We also retain reserves to provide for the proper conduct of our business, to stabilize distributions to our unitholders and our General Partner and, as necessary, to comply with the terms of our agreements or obligations (including any reserves required under debt instruments for future principal and interest payments and for future capital expenditures). We make distributions to our partners approximately 45 days following the end of each calendar quarter in accordance with their respective percentage interests.

Our General Partner is granted discretion by our partnership agreement, which discretion has been delegated to Enbridge Management, subject to the approval of our General Partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Enbridge Management determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Distributions of our available cash are generally made 98% to holders of our limited partner units and 2% to our General Partner. However, distributions are subject to the payment of incentive distributions to our General Partner to the extent that certain target levels of distributions to the unitholders are achieved. Before July 1, 2014 the incentive distributions payable to our General Partner were 15%, 25% and 50% of all quarterly distributions of available cash that exceed target levels of $0.295, $0.35 and $0.495 per limited partner units, respectively. After July 1, 2014, the incentive distributions payable to the IDUs are 25% of all quarterly distributions of available cash that exceed the target level of $0.5435 per limited partner unit. As set forth in our partnership agreement, we will not make cash distributions on our i-units, but instead, will distribute additional i-units such that the cash is retained and used in our operations and to finance a portion of our capital expansion projects.

Enbridge Management, as owner of the i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to our General Partner, holders of the Class D and Class E units, and holders of our Class A and Class B common units, the number of i-units owned by Enbridge Management and the percentage of our total units owned by Enbridge Management will increase automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's listed and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10 trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to our General Partner.

11. PARTNERS' CAPITAL – (continued)

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Management, during the years ended December 31, 2015, 2014 and 2013.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[1]	Retained from General Partner[2]	Distribution of Cash
				(in millions, except per unit amounts)			
2015							
October 30	November 6	November 13	$0.5830	$ 258.7	$ 41.8	$0.9	$216.0
July 30	August 7	August 14	$0.5830	257.9	41.0	0.8	216.1
April 30	May 8	May 15	$0.5700	249.9	39.5	0.8	209.6
January 29	February 6	February 13	$0.5700	233.9	38.9	0.8	194.2
				$1,000.4	$161.2	$3.3	$835.9
2014							
October 31	November 7	November 14	$0.5550	$ 221.8	$ 37.3	$0.8	$183.7
July 31	August 7	August 14	$0.5550	224.7	36.7	0.8	187.2
April 30	May 8	May 15	$0.5435	214.5	35.3	0.7	178.5
January 30	February 7	February 14	$0.5435	213.7	34.6	0.7	178.4
				$ 874.7	$143.9	$3.0	$727.8
2013							
October 31	November 7	November 14	$0.5435	$ 213.1	$ 34.1	$0.7	$178.3
July 29	August 7	August 14	$0.5435	206.8	28.9	0.6	177.3
April 30	May 8	May 15	$0.5435	206.2	28.4	0.6	177.2
January 30	February 7	February 14	$0.5435	198.9	22.4	0.4	176.1
				$ 825.0	$113.8	$2.3	$708.9

(1) We issued 4,980,552, 4,562,088 and 3,769,989 i-units to Enbridge Management, L.L.C., the sole owner of our i-units, during 2015, 2014 and 2013, respectively, in lieu of cash.

(2) We retained an amount equal to 2% of the i-unit distribution from our General Partner to maintain its 2% general partner interest in us.

12. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

We do not directly employ any of the individuals responsible for managing or operating our business, nor do we have any directors. Enbridge and its affiliates provide management and we obtain managerial, administrative, operational and workforce related services from our General Partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among our General Partner, Enbridge Management, affiliates of Enbridge, and us. Pursuant to these service agreements, we have agreed to reimburse our General Partner, Enbridge Management and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us. Where directly attributable, the cost 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.

The affiliate amounts incurred by us for services received pursuant to the services agreements are reflected in ''Operating and administrative — affiliate'' on our consolidated statements of income.

12. RELATED PARTY TRANSACTIONS – (continued)

Service Agreements

Our General Partner, Enbridge Management, Enbridge and affiliates of Enbridge provide managerial, administrative, operational and director services to us pursuant to service agreements, and we reimburse them for the costs of those services. Through an operational services agreement among Enbridge, Enbridge Operational Services, Inc., or EOSI, and Enbridge Pipelines, both subsidiaries of Enbridge, all of whom we refer to as the Canadian service providers, and us, we are charged for the services of Enbridge employees resident in Canada. Through a general and administrative services agreement among us, our General Partner, Enbridge Management and Enbridge Employee Services, Inc., or EES, we are charged for the services of employees resident in the United States. The charges related to these service agreements are included in ‘‘Operating and administrative — affiliate’’ expenses on our consolidated statements of income.

Operational Services Agreement

We are charged an amount by the Canadian service providers for services we are provided under the operational services agreement. The amount we are charged is established as part of the annual budget and agreed upon by us and the Canadian service providers. The amount we are charged is computed based on an estimate of the pro-rata reimbursement of each Canadian service provider's estimated annual departmental costs, net of amounts charged to other affiliates and amounts identifiable as costs of that Canadian service provider. The Canadian service providers charge us a monthly fixed fee that is computed as one-twelfth of the annual budgeted amount. Under the operational services agreement, our General Partner and Enbridge Management pay the Canadian service providers a monthly fee determined in the manner described above. At the request of Enbridge Management, the fee for these operational services provided to it in its capacity as the delegate of our General Partner are billed directly to us.

Enbridge Management and our General Partner may request that the Canadian service providers provide special additional operational services for which each, as appropriate, agrees to pay costs and expenses incurred by the Canadian service provider in connection with providing the special additional operational services. The types of services provided under the operational services agreement include:

- Executive, administrative and other services on an ‘‘as required’’ basis;
- Monitoring transportation capacity, scheduling shipments, standardizing integrity, maintenance and other operational requirements;
- Addressing regulatory matters associated with the liquids pipeline operations;
- Providing monthly measurement information, forecasts, oil accounting, invoicing and related services;
- Computer application development and support services, including liquid pipelines' control center operations;
- Electrical power requirements and costs for system operations;
- Patrol and aircraft services; and
- Any other operational services required to operate existing systems and any additional systems acquired by us.

Each year, the Canadian service providers prepare annual budgets by departmental cost center for their respective operations. After establishing a budget for the following year, the costs associated with each department are allocated to us, our General Partner, Enbridge Management and other Enbridge affiliates using one of the following three methods:

- Capital assets employed as a percentage of Enbridge-wide capital assets;
- Time-based estimates; or
- Full-time-equivalent (FTE)/headcount as a percentage of Enbridge-wide FTEs.

12. RELATED PARTY TRANSACTIONS – (continued)

The total amount we reimbursed the Canadian service providers pursuant to the operational services agreement for the years ended December 31, 2015, 2014 and 2013, was $213.0 million, $150.9 million and $154.9 million, respectively.

Line 6A and 6B Expense Reimbursement

For the years ended December 31, 2015, 2014 and 2013, we reimbursed Enbridge $0.1 million, $0.4 million and $0.5 million, respectively, for its assistance with the administration and clean-up efforts for our Line 6A and 6B crude oil releases. For further details related to our Line 6A and 6B crude oil releases, refer to Note 13. *Commitments and Contingencies — Lakehead Lines 6A and 6B Crude Oil Releases*.

General and Administrative Services Agreement

We, Enbridge Management and our General Partner receive services from EES under the general and administrative services agreement. Under this agreement, EES provides services to us, Enbridge Management and our General Partner and charges each recipient for services, on a monthly basis, the actual costs that it incurs for those services. Our General Partner and Enbridge Management may request that EES provide special additional general services for which each, as appropriate, agrees to pay costs and expenses incurred by EES in connection with providing the special additional general services. The types of services provided under the general and administrative services agreement include:

- Accounting, tax planning and compliance services, including preparation of financial statements and income tax returns;
- Administrative, executive, legal, human resources and computer support services;
- Insurance coverage;
- All administrative and operational services required to operate existing systems and any additional systems acquired by us and operated by EES; and
- Facilitate the business and affairs of Enbridge Management and us, including, but not limited to, public and government affairs, engineering, environmental, finance, audit, operations and operational support, safety/compliance and other services.

EES captures all costs that it incurs for providing the services by cost center in its financial system. The cost centers are determined to be ‘‘Shared Service,’’ ‘‘Enbridge Energy Partners, L.P. only’’ or ‘‘Non-Enbridge Energy Partners, L.P.’’ Shared Service cost centers are used to capture costs that are not specific to a single United States Enbridge entity but are shared among multiple United States Enbridge entities. The costs captured in the cost centers that are specific to us are charged in full to us. The costs captured in cost centers that are outside of our business unit are charged to other Enbridge entities.

The general method used to allocate the Shared Service costs is established through the budgeting process and reimbursed as follows:

- Each cost center establishes a budget.
- Each cost center manager estimates the amount of time the department spends on us and entities that are not directly affiliated with us.
- Costs are accumulated monthly for each cost center.
- The actual costs accumulated monthly by each cost center are allocated to us or entities that are not directly affiliated with us based on the allocation model.
- We reimburse EES for its share of the allocated costs.

The total amount reimbursed by us for services received pursuant to the general and administrative services agreement for the years ended December 31, 2015, 2014 and 2013, was $294.0 million, $179.0 million and $284.1 million, respectively.

12. RELATED PARTY TRANSACTIONS – (continued)

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of $32.6 million, $44.3 million and $51.7 million during 2015, 2014 and 2013, respectively, that we recorded as additions to ''Property, plant and equipment, net'' on our consolidated statements of financial position.

Enbridge Management

Pursuant to the delegation of control agreement between Enbridge Management, our General Partner and us, and our partnership agreement, we pay all expenses relating to Enbridge Management. These expenses are not material during the years ended December 31, 2015, 2014 and 2013. This includes Texas franchise taxes and other capital-based foreign, state and local taxes not otherwise paid or reimbursed pursuant to a tax indemnification agreement between Enbridge and Enbridge Management on behalf of Enbridge Management.

Insurance Allocation Agreement

We participate in the comprehensive insurance program that is maintained by Enbridge for it and its subsidiaries. In December 2012, we entered into an insurance allocation agreement with Enbridge and another Enbridge subsidiary, which was amended and restated on November 13, 2013, to add MEP as a party. Under this agreement, 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.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, and 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 the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. 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.

We and MEP act in an administrative capacity as collection agents on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. We 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 ''Operating and administrative — affiliate'' expense in our consolidated statements of income. For the years ended December 31, 2015 and 2014, the cost stemming from the discount on the receivables sold was not material.

For the years ended December 31, 2015 and 2014, we sold and derecognized receivables of $3,710.4 million and $4,987.0 million, respectively. For the years ended December 31, 2015 and 2014, the cash proceeds were $3,709.3 million and $4,985.7 million, respectively, which was remitted to us through our centralized treasury system. As of December 31, 2015 and 2014, $317.0 million and $378.0 million, respectively, of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

As of December 31, 2015 and December 31, 2014, we had $19.0 million and $71.9 million, respectively, in ''Restricted cash'' on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary.

Affiliate Revenues and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale and are

12. RELATED PARTY TRANSACTIONS – (continued)

presented in ''Commodity sales — affiliate'' on our consolidated statements of income. We also record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates, which are presented in ''Transportation and other services — affiliate'' on our consolidated statements of income.

We also purchase natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Purchases of natural gas, NGLs, and crude oil from Enbridge and its affiliates are presented in ''Commodity costs — affiliate'' on our consolidated statements of income.

Facilities Cost Reimbursement Agreement

We have an agreement with Enbridge Pipelines to install and operate certain sampling and related facilities for the purpose of improving the quality of crude oil and the transportation services on our Lakehead system, which directly increases the transportation services revenue of Enbridge Pipelines. As compensation for installing and operating these transportation facilities, Enbridge Pipelines makes annual payments to us on a cost of service basis. The income we recorded for providing these transportation services in 2015, 2014 and 2013 was approximately $0.8 million, $0.8 million and $0.8 million, respectively.

Lease and Storage Services Agreement

We have an agreement with Illinois Extension Pipeline Company, L.L.C., or IEPC, an equity method investment of our General Partner, pursuant to which IEPC built two storage tanks at our storage facility in Flanagan, Illinois. We lease the tanks from IEPC and operate them. IEPC will pay us operating fees for the operation of the tanks. For the year ended December 31, 2015, IEPC paid no operating fees to us.

Related Party Transactions with Joint Ventures

We have a 35% aggregate indirect interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together include a 593-mile NGL intrastate transportation pipeline and a related NGL gathering system. Our equity investment in the Texas Express NGL system at December 31, 2015 and 2014, was $372.3 million and $380.6 million, respectively, which is included on our consolidated statements of financial position in ''Other assets, net.'' For the years ended December 31, 2015, 2014 and 2013, we recognized $29.2 million, $13.2 million and $(1.0) million of equity earnings (losses), respectively, in ''Other income (expense)'' on our consolidated statements of income related to our investment in the system.

For the years ended December 31, 2015, 2014 and 2013, we incurred $18.4 million, $21.9 million and $3.2 million, respectively, of pipeline transportation and demand fees from Texas Express NGL system for our Natural Gas business. These expenses are recorded in ''Commodity costs — affiliate'' on our consolidated statements of income.

Our Natural Gas business has made commitments to transport up to 120,000 bpd of NGLs on the Texas Express NGL system from 2015 to 2022. The current commitment level is 29,000 Bpd.

Conflicts of Interest

Enbridge Management makes all decisions relating to the management of our business and affairs through a delegation of control agreement with our General Partner and us. Our General Partner owns the voting shares of Enbridge Management and elects all of its directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines, owns all the common stock of our General Partner. Some of our General Partner's directors and officers are also directors and officers of Enbridge and Enbridge Management and have fiduciary duties to manage the business of Enbridge and Enbridge Management in a manner that may not be in the best interests of our unitholders. Certain conflicts of interest could arise as a result of the relationships among Enbridge Management, our General Partner, Enbridge and us. Our partnership agreement and the delegation of control agreement contain provisions that allow Enbridge Management to take into account the interest of all parties in addition to those of our unitholders in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

12. RELATED PARTY TRANSACTIONS – (continued)

General Partner Equity Transactions

Our General Partner owns an effective 2% general partner interest in us. The cash distributions we make to our General Partner exclude an amount equal to 2% of the i-units, which we retain from the General Partner to maintain its 2% general partner interest in us.

Our General Partner's outstanding ownership interests on us at December 31, 2015 and 2014, and the total distributions we paid to the General Partner for the years ending December 31, 2015, 2014 and 2013 were as follows:

	General Partner's Ownership Interests				Cash Distributions Paid to General Partner		
	(in units)		(percentage)		(in millions)		
Type of Unit	2015	2014	2015	2014	2015	2014	2013
Series 1 preferred units[(1)]	48,000,000	48,000,000	9.9%	10.6%	$ —	$ —	$ —
Class D units	66,100,000	66,100,000	13.6%	14.6%	$152.4	$ 69.8	$ —
Class E units	18,114,975	—	3.7%	0.0%	$ 31.5	$ —	$ —
Class A common units	46,518,336	46,518,336	9.6%	10.3%	$107.3	$102.2	$101.1
Class B common units	7,825,500	7,825,500	1.6%	1.7%	$ 18.1	$ 17.3	$ 17.0
IDUs	1,000	1,000	0.0%	0.0%	$ 17.0	$ 2.8	$ —
General Partner interest[(2)]	—	—	2.0%	2.0%	$ 16.8	$ 79.5	$139.3
Enbridge Management shares (Listed and Voting)	8,564,645	7,982,586	1.8%	1.8%	$ —	$ —	$ —
Total	195,124,456	176,427,422	42.2%	41.0%	$343.1	$271.6	$257.4

(1) Includes $161.2 million and $143.9 million total accrued distributions included in the consolidated statements of financial position at December 31, 2015 and 2014, respectively.

(2) Includes $2.9 million and $2.3 million total incentive distributions paid at December 31, 2014 and 2013, respectively, to the General Partner before the IDUs were issued.

Financing Transactions with Affiliates

EUS 364-day Credit Facility

On March 9, 2015, we entered into an unsecured revolving 364-day credit agreement with EUS, which we refer to as the EUS 364-day Credit Facility. The EUS 364-day Credit Facility is a committed senior unsecured revolving credit facility that previously permitted aggregate borrowings of up to, at any one time outstanding, $750 million, (1) on a revolving basis for a 364-day period and (2) for a 364-day term on a non-revolving basis following the expiration of the revolving period. Loans under the EUS 364-day Credit Facility accrue interest based, at our election, on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. The EUS 364-day Credit Facility terminates on March 7, 2016, and including the option to term the revolving loan for a period of 364-days following the termination date, matures on March 6, 2017. There is no outstanding balance as of December 31, 2015 under the EUS 364-day Credit Facility.

The commitment under the EUS 364-day Credit Facility may be permanently reduced by EUS, from time to time, by up to an amount equal to the net cash proceeds to us from the sale by us of (1) debt or equity securities in a registered public offering, or (2) limited partnership interests in Midcoast Operating to MEP. On November 16, 2015, EUS elected to reduce its commitment to zero under the EUS 364-day Credit Facility.

Initial Public Offering of MEP

On November 13, 2013, MEP completed its initial public offering of Class A common units, representing limited partner interests in MEP. On the same date, in connection with the closing of that offering, certain transactions, among others, occurred pursuant to which we effectively conveyed to MEP all of our limited liability company interests in the general partner of the operating subsidiary of MEP, or Midcoast Operating and a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units and MEP

12. RELATED PARTY TRANSACTIONS – (continued)

Subordinated Units, approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the contributed businesses, and a right to receive $323.4 million in cash.

Distribution from MEP

The following table presents distributions paid by MEP during the years ended December 31, 2015 and 2014, to its public Class A common unitholders, representing the noncontrolling interest in MEP, and to us for our ownership of Class A common units.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total MEP Distribution
			(in millions)	
2015				
October 29	November 13	$ 8.9	$ 7.6	$16.5
July 29	August 14	8.8	7.5	16.3
April 29	May 15	8.6	7.4	16.0
January 28	February 13	8.5	7.3	15.8
		$34.8	$29.8	$64.6
2014				
October 30	November 14	$ 8.4	$ 7.2	$15.6
July 31	August 14	8.1	6.9	15.0
April 29	May 15	7.8	6.6	14.4
January 29	February 14	4.2	3.5	7.7
		$28.5	$24.2	$52.7

Joint Funding Arrangement for Alberta Clipper Pipeline

Until January 2, 2015, we had a joint funding arrangement with several of our affiliates and affiliates of Enbridge to finance the construction of the United States segment of the Alberta Clipper Pipeline, which we refer to as the Series AC. On January 2, 2015, we completed the Drop Down transaction pursuant to which the General Partner and its affiliates contributed to us the remaining 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline in exchange for approximately 18,114,975 units of a new class of limited partner interests designated as Class E units with a fair value of $767.7 million.

As part of the joint funding arrangement, we had borrowings outstanding and payable to our General Partner under a promissory note, which we refer to as the A1 Term Note. The A1 Term Note bore interest at a fixed rate of 5.20% and had a maximum loan amount of $400.0 million. Pursuant to the terms of the A1 Term Note, we were required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments were based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline, with the unpaid balance due in 2020. The A1 Term Note had recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and was subordinate to all of our senior indebtedness.

12. RELATED PARTY TRANSACTIONS – (continued)

As part of the Drop Down, we repaid the borrowings outstanding of $306.0 million on the A1 Term Note. A summary of the cash activity for the A1 Term Note for the years ended December 31, 2015, 2014 and 2013, are as follows:

	A1 Term Note
	(in millions)
Balance at December 31, 2013	$ 318.0
Repayments	(12.0)
Balance at December 31, 2014	306.0
Repayments	(306.0)
Balance at December 31, 2015	$ —

We incurred interest expense under the A1 Term Note of $24.3 million and $25.2 million for the years ended December 31, 2014 and 2013, respectively. We have presented the amounts in ‘‘Interest expense, net’’ on our consolidated statements of income.

Distribution to Series AC Interests

The following table presents the distributions paid by the OLP during the years ended December 31, 2015, 2014 and 2013, to our General Partner and its affiliate, representing the noncontrolling interest in the Series AC, and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests. Pursuant to the OLP's partnership agreement, the final ownership distribution for the Series AC interests was distributed to Series AC partners of record as of the last day of the fourth quarter of 2014.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount Paid to the noncontrolling interest	Total Series AC Distribution
			(in millions)	
2015				
January 29	February 13	$13.7	$27.5	$41.2
2014				
October 31	November 14	$10.1	$20.3	$30.4
July 31	August 14	7.4	14.8	22.2
April 30	May 15	6.6	13.1	19.7
January 30	February 14	6.4	12.8	19.2
		$30.5	$61.0	$91.5
2013				
October 31	November 14	$ 7.0	$14.1	$21.1
July 29	August 14	5.5	11.0	16.5
April 30	May 15	7.5	14.9	22.4
January 30	February 14	6.9	13.8	20.7
		$26.9	$53.8	$80.7

12. RELATED PARTY TRANSACTIONS – (continued)

Amendment of OLP Limited Partnership Agreement

On July 30, 2015, the partners amended and restated the limited partnership agreement of the OLP pursuant to which our General Partner will temporarily forego Series EA and ME, collectively, the Series, distributions commencing in the quarter ended June 30, 2015, through the quarter ending March 31, 2016. The General Partner's capital funding contribution requirements for each of those two Series, commencing in August 2015, will be reduced by the amount of its foregone cash distributions from the respective Series, until the earlier of December 31, 2016 and the date aggregate reductions in capital contributions for such Series are equal to the foregone cash distributions for such Series. To the extent that the General Partner's portion of capital contributions prior to December 31, 2016 are insufficient to cover the General Partner's foregone cash distributions for a Series, beginning with the distribution related to the first quarter of 2017 for that Series, we will receive reduced cash distributions by up to 50%, and the General Partner will receive a comparable increase in cash distributions each quarter until the General Partner has received an aggregate amount of contribution reductions and distribution increases equal to the amount of foregone cash distributions.

Joint Funding Arrangement for Eastern Access Projects

We have a joint funding arrangement with the General Partner that establishes an additional series of partnership interests in the OLP, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% all assets, liabilities and operations related to the Eastern Access Projects.

On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for mid-2016, we have the option to increase our economic interest by up to 15 percentage points. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects. Our General Partner now owns 75% of the EA interests, and, except as described above in *Amendment of OLP Limited Partnership Agreement*, the Eastern Access Projects are jointly funded by our General Partner at 75% and us at 25%.

Our General Partner has made equity contributions totaling $119.3 million, $622.5 million and $609.2 million to the OLP for the years ended December 31, 2015, 2014 and 2013, respectively to fund its equity portion of the construction costs associated with the Eastern Access Projects. During December 2015, the OLP made equity distributions of $81.6 million to our General Partner, representing return of capital for excess capital funds contributed by our General Partner to the Eastern Access Projects. This is included in "Distributions to noncontrolling interest" presented in our statement of cash flows.

12. RELATED PARTY TRANSACTIONS – (continued)

Distribution to Series EA Interests

The following table presents distributions paid by the OLP during the years ended December 31, 2015 and 2014, to our General Partner and its affiliate, representing the noncontrolling interest in the Series EA, and to us, as the holders of the Series EA general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series EA interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series EA Distribution
			(in millions)	
2015				
October 30	November 13	$ 76.1	$ —	$ 76.1
July 30	August 14	75.4	—	75.4
April 30	May 15	17.5	52.3	69.8
January 29	February 13	22.3	67.0	89.3
		$191.3	$119.3	$310.6
2014				
October 31	November 14	$ 14.6	$ 43.7	$ 58.3
July 31	August 14	5.6	16.7	22.3
April 29	May 15	2.5	6.5	9.0
		$ 22.7	$ 66.9	$ 89.6

Joint Funding Arrangement for U.S. Mainline Expansion Projects

We have a joint funding arrangement with the General Partner that establishes another series of partnership interests in the OLP, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and us at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement.

On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points. All other operations are captured by the Lakehead interests. We received $12.0 million from our General Partner in consideration for our economic interest. Our General Partner now owns 75% of the ME interests, and, except as described above in *Amendment of OLP Limited Partnership Agreement*, the U.S. Mainline Expansion Projects are jointly funded by our General Partner at 75% and us at 25%.

Our General Partner has made equity contributions totaling $673.3 million, $577.5 million and $159.9 million to the OLP for the years ended December 31, 2015, 2014 and 2013, respectively, to fund its equity portion of the construction costs associated with the U.S. Mainline Expansion Projects. During December 2015, the OLP made equity distributions of $71.5 million to our General Partner, representing return of capital for excess capital funds contributed by our General Partner to the U.S. Mainline Expansion Projects. This is included in ''Distributions to noncontrolling interest'' presented in our statement of cash flows.

Distribution to Series ME Interests

The following table presents distributions paid by the OLP during the years ended December 31, 2015 and 2014, to our General Partner and its affiliate, representing the noncontrolling interest in the Series ME, and to us, as the holders of the Series ME general and limited partner interests. The distributions were declared by the board of

12. RELATED PARTY TRANSACTIONS – (continued)

directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series ME interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series ME Distribution
			(in millions)	
2015				
October 30	November 13	$32.5	$ —	$32.5
July 30	August 14	19.7	—	19.7
April 30	May 15	1.5	4.5	6.0
January 29	February 13	1.8	5.2	7.0
		$55.5	$9.7	$65.2
2014				
October 31	November 14	$ 0.6	$1.9	$ 2.5

Noncontrolling Interests

The following table presents the components of net income (loss) attributable to noncontrolling interests as presented on our consolidated statements of income:

	For the year ended December 31		
	2015	2014	2013
		(in millions)	
Alberta Clipper Interests	$ (0.8)	$ 54.6	$52.6
Eastern Access Interests	189.3	145.3	32.1
U.S. Mainline Expansion Interests	108.2	33.8	4.3
Midcoast Energy Partners, L.P.	(75.6)	29.6	(0.7)
Total	$221.1	$263.3	$88.3

Other Agreements with MEP

In connection with the closing of MEP's initial public offering on November 13, 2013, we entered into the following agreements:

Omnibus Agreement

We, Midcoast Holdings, L.L.C., or the MEP General Partner, MEP, and Enbridge, entered in the Omnibus Agreement to which we agreed to indemnify MEP for certain matters, including environmental, right-of-way and permit matters, and we granted MEP a license to use the Enbridge logo and certain other trademarks and tradenames. The Omnibus Agreement may be terminated by the mutual agreement of the parties, or by either Enbridge or MEP in the event that we cease to control the MEP General Partner, provided that our indemnification obligations will remain in full force and effect until they expire in accordance with their respective terms.

Under the Omnibus Agreement, we also agreed to indemnify MEP for all known and certain unknown environmental liabilities that are associated with the ownership or operation of MEP's assets arising prior to the closing of MEP's initial public offering, in each case that are identified prior to the third anniversary of the closing of that offering. Our obligation to indemnify MEP for any environmental liabilities is subject to a $500,000 aggregate deductible before MEP is entitled to indemnification. We will also indemnify MEP for failure to have certain rights-of-way, consents, licenses and permits necessary to own and operate its assets in substantially the same manner in which they were owned and operated prior to the closing of the Offering, including the cost of curing certain such failures that do not allow its assets to be operated in accordance with prudent industry practice, in each case that are identified prior to the third anniversary of the closing of the Offering. Our obligation to indemnify MEP for any right-of-way, consent, license or permit matters will be subject to a $500,000 aggregate

12. RELATED PARTY TRANSACTIONS – (continued)

deductible before MEP is entitled to indemnification. There will be a $15.0 million aggregate cap on the amounts for which we will indemnify MEP for environmental, right-of-way, consents, licenses and permit matters under the Omnibus Agreement.

Intercorporate Services Agreement

We entered into an Intercorporate Service Agreement, or the Intercorporate Services Agreement, with MEP, pursuant to which we will provide MEP 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 MEP'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
- other services as MEP may request.

Under the Intercorporate Services Agreement, MEP will reimburse us and our affiliates for the costs and expenses incurred in providing such services to MEP; however, we reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually.

Financial Support Agreement

We entered into a Financial Support Agreement with Midcoast Operating, or the Financial Support Agreement, pursuant to which we 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, our support of Midcoast Operating's and its wholly owned subsidiaries' obligations will terminate on the earlier of (1) November 13, 2017, and (2) the date on which we own, directly or indirectly (other than through our ownership interests in MEP), less than 20% of the total outstanding limited partner interests in Midcoast Operating.

The Financial Support Agreement also provides that if MEPs bank credit agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. We also have agreed to subordinate our right to payment on obligations owed under the Financial Support Agreement and liens, if secured, to the rights of the lenders under the MEP credit agreement.

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 liquid hydrocarbon and natural gas pipeline operations, 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 other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our Liquids and Natural Gas businesses. Our General Partner has agreed to

13. COMMITMENTS AND CONTINGENCIES – (continued)

indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate 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, 2015 and 2014, we had $95.8 million and $141.7 million, respectively, included in "Environmental liabilities," and $64.0 million and $60.1 million, respectively, included in "Other long-term liabilities," on our consolidated statements of financial position that we have accrued for costs we have recognized primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Lakehead Lines 6A & 6B Crude Oil Releases

Line 6A Crude Oil Release

A release of crude oil from Line 6A of our Lakehead system was reported in an industrial area of Romeoville, Illinois on September 9, 2010. We estimate that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. We completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

We have completed the cleanup, remediation and restoration of the areas affected by the release. On October 21, 2013, the National Transportation Safety Board, or NTSB, publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois on September 9, 2010, which states that the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below our oil pipeline.

The total cost estimate for this crude oil release was approximately $51.0 million, before insurance recoveries and excluding fines and penalties. These costs included the emergency response, environmental remediation and cleanup activities associated with the crude oil release. For the years ended December 31, 2015 and 2013, we paid $0.6 million and $1.5 million, respectively, related to the costs on the Line 6A release, with no such costs paid in 2014. For the year ended December 31, 2015, we had no remaining estimated liability and for the year ended December 31, 2014 we had remaining estimated liability of $3.0 million.

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of our Lakehead system was reported near Marshall, Michigan. We estimate that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Kalamazoo River via Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 38 miles of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan.

We continue to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives we are undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On March 14, 2013, we received an order from the EPA, which we refer to as the Order, that required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. In February 2015, the EPA acknowledged our completion of the Order.

In November 2014, regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality, or MDEQ. The MDEQ has oversight over submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

13. COMMITMENTS AND CONTINGENCIES – (continued)

In May 2015, Enbridge reached a settlement with the MDEQ and the Michigan Attorney General's offices regarding the Line 6B crude oil release. As stipulated in the settlement, Enbridge agrees to: (1) provide at least 300 acres of wetland through restoration, creation, or banked wetland credits, to remain as wetland in perpetuity, (2) pay $5.0 million as mitigation for impacts to the banks, bottomlands, and flow of Talmadge Creek and the Kalamazoo River for the purpose of enhancing the Kalamazoo River watershed and restoring stream flows in the River, (3) continue to reimburse the State of Michigan for costs arising from oversight of Enbridge activities since the release, and (4) continue monitoring, restoration and invasive species control within state-regulated wetlands affected by the release and associated response activities. The timing of these activities is based upon the work plans approved by the State of Michigan.

As of December 31, 2015, our total cost estimate for the Line 6B crude oil release is $1.21 billion, which is unchanged since December 31, 2014. As of December 31, 2014, our total cost estimate for the Line 6B crude oil release increased by $85.9 million as compared to December 31, 2013. The total cost increase of $85.9 million during the year ended December 31, 2014, is primarily related to the MDEQ approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake, and estimated civil penalties under the Clean Water Act of the United States, as described below under *Lines 6A & 6B Fines and Penalties*.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at December 31, 2015. Our estimates exclude: (1) amounts we have capitalized, (2) any claims associated with the release that may later become evident, (3) amounts recoverable under insurance, and (4) fines and penalties from other governmental agencies except as described in the Line 6A & 6B Fines and Penalties section below. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release 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.

The material components underlying our cumulative estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release include the following:

	(in millions)
Response personnel and equipment	$ 548.5
Environmental consultants	227.0
Professional, regulatory and other	432.5
Total	$1,208.0

For the years ended December 31, 2015, 2014 and 2013, we made payments of $37.2 million, $141.4 million and $156.3 million, respectively, for costs associated with the Line 6B crude oil release. For the years ended December 31, 2015 and 2014, we had a remaining estimated liability of $149.8 million and $195.2 million, respectively. Additionally, we recognized $42.0 million of insurance recoveries in our consolidated statements of income for the year ended December 31, 2013. We did not recognize any insurance recoveries for the years ended December 31, 2015 and 2014.

Fines and Penalties

At December 31, 2015, our remaining estimated costs related to the Line 6B crude oil release included $43.7 million in fines and penalties. Of this amount, $40.0 million relates to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, we believe that, based

13. COMMITMENTS AND CONTINGENCIES – (continued)

on the best information available at this time, the $40.0 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which we expect will continue, and the limited information available to assess the matter, we are unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection, and emergency response to environmental events, and the cost of compliance with such measures, when combined with any fine or penalty, could be material. We have entered into a tolling agreement with the applicable governmental agencies and discussions with these governmental agencies regarding fines, penalties, and injunctive relief are ongoing.

In June 2015, Enbridge reached a separate agreement with the United States of America (Federal Natural Resources Damages Trustees), State of Michigan (State Natural Resources Damages Trustees), Match-E-Be-Nash-She-Wish Band of the Potawatomi Indians, and the Nottawaseppi Huron Band of the Potawatomi Indians, and we paid approximately $3.9 million that we had accrued to cover a variety of projects, including the restoration of 175 acres of oak savanna in Fort Custer State Recreation Area and wild rice beds along the Kalamazoo River.

Insurance

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates that renew throughout the year. On May 1 of each year, our insurance program is renewed and includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry and includes coverage for environmental incidents such as those we have incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties.

A majority of the costs incurred for the crude oil release for Line 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650.0 million for pollution liability for Enbridge and its affiliates. Including our remediation spending through December 31, 2015, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. As of December 31, 2015, we have recorded total insurance recoveries of $547.0 million for the Line 6B crude oil release, out of the $650.0 million aggregate limit. We will record receivables for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

In March 2013, we and Enbridge filed a lawsuit against the insurers of $145.0 million of coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers and amended our lawsuit such that it included only one insurer.

Of the remaining $103.0 million coverage limit, $85.0 million is the subject matter of a lawsuit Enbridge filed against one particular insurer described above. In March 2015, Enbridge reached agreement with that insurer to submit the $85.0 million claim to binding arbitration. The recovery of the remaining $18.0 million is awaiting resolution of that arbitration, which is not scheduled to occur until fourth quarter of 2016. While we believe that those costs are eligible for recovery, there can be no assurance that we will prevail in the arbitration.

We are pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained. Additionally, fines and penalties would not be covered under our existing insurance policy.

Enbridge renewed its comprehensive property and liability insurance programs, under which we, together with Enbridge and its other affiliates are insured through April 30, 2016, with a liability program aggregate limit of $860.0 million, which includes sudden and accidental pollution liability. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur 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 we have entered into with Enbridge, MEP, and other Enbridge subsidiaries.

13. COMMITMENTS AND CONTINGENCIES – (continued)

Griffith Terminal Crude Oil Release

On February 25, 2014, a release of approximately 975 barrels of crude oil occurred within the Griffith Terminal in Griffith, Indiana. A repair plan has been reviewed with PHMSA and repair work has commenced. The released oil was fully contained within our facility and substantially all of the free product was recovered. The released oil did not affect the local community, wildlife or water supply. As of and for the year ended December 31, 2015, we had no remaining estimated liability and made no payments. As of and for the year ended 2014, we had a remaining estimated liability of $0.7 million and made payments of $6.3 million.

Lakehead Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of our Lakehead system near Grand Marsh, Wisconsin. The estimate of volume of the oil released was approximately 1,700 barrels. We received a CAO, from PHMSA, on July 30, 2012 followed by an amended CAO, which we refer to as the PHMSA Corrective Action Orders, on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013 we received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of twelve months. In December 2014, PHMSA again considered the status of the pipeline in light of information they acquired throughout 2014. On December 9, 2014, we received a letter from PHMSA approving our request to continue the normal operation of Line 14 without pressure restrictions. We have no remaining estimated liability for this release.

Legal and Regulatory Proceedings

We are a participant in various legal and regulatory proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We are also directly, or indirectly, subject to challenges by special interest groups to regulatory approvals and permits for certain of our expansion projects.

A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Five actions or claims are pending against us and our affiliates, in state and federal courts in connection with the Line 6B crude oil release. Based on the current status of these cases, we do not expect the outcome of these actions to be material to our results of operations or financial condition.

Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim was filed against us and our affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release. The costs associated with this order are included in the estimated environmental costs accrued for the Line 6A crude oil release. On February 20, 2015, we agreed to a consent order releasing us from any claims, liability, or penalties. We are also pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

We have accrued a provision for future legal costs and probable losses associated with the Line 6A and Line 6B crude oil releases as described above in this footnote.

On July 25, 2013, the United States Department of Justice, or DOJ, and the EPA filed a complaint against us related to permit violations for the discharge of hydrotest water in 2010 related to the Alberta Clipper Pipeline and one of our affiliates. On August 30, 2013, we settled with the DOJ and EPA for $254 thousand related to the Alberta Clipper Pipeline portion of the permit violation.

Oil and Gas in Custody

Our Liquids assets transport crude oil and NGLs owned by our customers for a fee. The volume of liquid hydrocarbons in our pipeline systems at any one time varies from approximately 29.7 million to 63.6 million barrels, virtually all of which is owned by our customers. Under the terms of our tariffs, losses of crude oil from identifiable incidents not resulting from our direct negligence may be apportioned among our customers. In addition, we maintain adequate property insurance coverage with respect to crude oil and NGLs in our custody.

Approximately 40% of the natural gas volumes on our Natural Gas assets are transported for customers on a contractual basis. We purchase the remaining volumes and sell to third parties downstream of the purchase point. At

13. COMMITMENTS AND CONTINGENCIES – (continued)

any point in time, the value of our customers' natural gas in the custody of our Natural Gas systems 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 $2.7 million, $3.6 million and $2.3 million for the leased right-of-way agreements for the years ended December 31, 2015, 2014 and 2013, respectively.

Future Minimum Commitments

As of December 31, 2015, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

	2016	2017	2018	2019	2020	Thereafter	Total
				(in millions)			
Purchase commitments(1)	$697.4	$ —	$ —	$ —	$ —	$ —	$ 697.4
Power commitments(2)	20.2	20.2	20.1	19.7	17.7	132.1	230.0
Operating leases	19.3	16.7	14.8	14.2	14.0	58.9	137.9
Right-of-way	2.0	1.7	1.7	1.7	1.5	34.5	43.1
Product purchase obligations(3)	44.2	15.4	24.8	25.5	26.5	85.9	222.3
Transportation/Service contract obligations(4)	56.1	112.9	125.2	129.2	125.5	338.7	887.6
Fractionation agreement obligations(5)	75.1	74.8	74.8	74.8	75.1	156.1	530.7
Total	$914.3	$241.7	$261.4	$265.1	$260.3	$806.2	$2,749.0

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

(2) Represents commitments to purchase power in connection with our Liquids segment. We included certain power commitments with obligations that are dependent on variable components. For these commitments, we only included the determinable portion of our commitment based on the contracted usage requirement and the current applicable contract rate.

(3) Represents long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at the approximate market value at the time of delivery.

(4) Represents the minimum payment amounts for contracts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

(5) Represents the minimum payment amounts from contracts for firm fractionation of our NGL supply that we reserve at third party fractionation facilities.

Purchases made under our non-cancelable commitments for the years ended December 31, 2015, 2014 and 2013 were $423.4 million, $1.9 billion and $590.7 million, respectively.

Our consolidated operating expenses include lease and rental expense amounts of $14.9 million, $18.2 million and $25.0 million during the years ended December 31, 2015, 2014 and 2013, respectively.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding commodity costs of natural gas and natural gas liquids we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments, such as 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 in our cash flows. Based on our risk management policies, all of our derivative financial instruments, including those that are not designated for hedge accounting treatment, are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with the risks discussed above in future periods in accordance with our risk management policies. Our derivative instruments that are designated for hedge accounting under authoritative guidance are classified as cash flow hedges.

Derivative Positions

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

	December 31, 2015	December 31, 2014
	(in millions)	
Other current assets	$ 123.9	$ 185.5
Other assets, net	39.7	93.3
Accounts payable and other[1]	(130.9)	(315.4)
Other long-term liabilities	(90.6)	(124.6)
Due from general partner and affiliates	—	0.3
	$ (57.9)	$(160.9)

[1] Includes $12.6 million and $28.4 million held of cash collateral at December 31, 2015 and 2014, respectively.

The changes in the 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 the following contracts: (1) natural gas, (2) NGL, (3) crude oil and (4) interest rates.

Our earnings and cash flows are exposed to the variability in longer term interest rates ahead of the anticipated fixed rate debt issuances. Forward starting interest rate swaps are used as cash flow hedges against the effect of future interest rate movements on earnings and cash flow. In order to mitigate the negative effect that increasing interest rates have on our cash flows, prior to 2014, we purchased 10-year interest rate swaps with a total notional value of $2.35 billion.

In September 2014, we amended the maturity date on certain interest rate hedges of future debt issuances that were originally set to mature in 2014 and 2016 to better reflect the expected timing of future debt issuances. The ineffective portion of the hedges' fair value in relation to the hedged future debt issuances is recognized in income at the amendment date and each quarter end. For the years ended December 31, 2015 and 2014, we recognized in interest expense unrealized gains for hedge ineffectiveness of approximately $96.2 million and unrealized losses of approximately $100.6 million, respectively, associated with interest rate hedges that were originally set to mature in 2014 and 2016.

During the years ended December 31, 2014 and 2013, we determined that a portion of forecasted short-term debt transactions were not expected to occur, due to changing funding requirements. Since we required less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer met the cash flow hedging requirements. These terminations resulted in realized losses of $0.8 million and $5.3 million of additional interest expense for the years ended December 31, 2014 and 2013, respectively.

On October 6, 2015, we closed a public offering of $1.6 billion of senior unsecured notes for net proceeds of approximately $1.575 billion after deducting underwriting discounts and commissions and estimated offering expenses. In connection with the offering, we paid $314.7 million to settle certain pre-issuance hedges. As of December 31, 2015, the remaining amount of the effective portion of the hedge of $232.1 million, which is net of $6.2 million in amortization that was reclassified into earnings, is recorded in AOCI and will be amortized as

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

interest expense over a term of eight to ten years. For the year ended December 31, 2015, $82.6 million, inclusive of amounts reclassified into earnings, is included in ''Interest expense'' in the consolidated statement of income

Interest expense for the year ended December 31, 2013, also includes unrealized losses from reductions to AOCI for hedge ineffectiveness of approximately $29.6 million associated with interest rate hedges that were originally set to mature in December 2013. However, in November 2013, these hedges were amended to extend the maturity date to December 2014 to better reflect the expected timing of future debt issuances.

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

	December 31,	
	2015	2014
	(in millions)	
Counterparty Credit Quality[1]		
AAA	$ —	$ 0.1
AA[2]	(12.4)	(49.8)
A	(10.5)	(129.1)
Lower than A	(35.0)	17.9
	$(57.9)	$(160.9)

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

(2) Includes $12.6 million and $28.4 million of cash collateral held at December 31, 2015 and 2014, respectively.

As the net value of our derivative financial instruments has increased in response to changes in forward commodity prices and interest rates, our outstanding financial exposure to third parties has also increased. 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 or posted in the balances listed above. As of December 31, 2015 and December 31, 2014, we held $12.6 million and $28.4 million, respectively, in cash collateral on our asset exposures. Cash collateral is classified as ''Restricted cash'' in our consolidated statements of financial position. 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.

We provided letters of credit totaling $120.1 million and $329.6 million relating to our liability exposures pursuant to the margin thresholds in effect at December 31, 2015 and 2014, respectively, under our ISDA® agreements. 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 interest rate and 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.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

In the event that our credit ratings were to decline below the lowest level of investment grade, as determined by Standard & Poor's and Moody's, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been below the lowest level of investment grade at December 31, 2015 we would have been required to provide additional letters of credit in the amount of $52.5 million, related to our open positions.

At December 31, 2015 and 2014, we had credit concentrations in the following industry sectors, as presented below:

	December 31, 2015	December 31, 2014
	(in millions)	
United States financial institutions and investment banking entities[1]	$(30.9)	$(147.1)
Non-United States financial institutions	(51.0)	(54.2)
Other	24.0	40.4
	$(57.9)	$(160.9)

[1] Includes $12.6 million and $28.4 million of cash collateral held at December 31, 2015 and 2014, respectively.

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 OTC derivatives is directly with our counterparty and continues until the maturity or termination of the contracts.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Financial Position Location	Asset Derivatives Fair Value at December 31, 2015	Asset Derivatives Fair Value at December 31, 2014	Liability Derivatives Fair Value at December 31, 2015	Liability Derivatives Fair Value at December 31, 2014
		(in millions)			
Derivatives designated as hedging instruments:[1]					
Interest rate contracts	Accounts payable and other	$ —	$ —	$ (85.2)	$(241.0)
Interest rate contracts	Other long-term liabilities	—	—	(72.3)	(102.0)
Commodity contracts	Other current assets	—	26.1	—	—
Commodity contracts	Other assets	—	2.1	—	—
		—	28.2	(157.5)	(343.0)
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	123.9	159.4	—	—
Commodity contracts	Other assets	39.7	91.2	—	—
Commodity contracts	Accounts payable and other[2]	—	—	(33.1)	(46.0)
Commodity contracts	Other long-term liabilities	—	—	(18.3)	(22.6)
Commodity contracts	Due from general partner and affiliates	—	0.3	—	—
		163.6	250.9	(51.4)	(68.6)
Total derivative instruments		$163.6	$279.1	$(208.9)	$(411.6)

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

[2] Liability derivatives exclude $12.6 million and $28.4 million of cash collateral held at December 31, 2015 and 2014, respectively.

Accumulated Other Comprehensive Income

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. As of December 31, 2015 and 2014, we included in AOCI unrecognized losses of approximately $255.5 million and $28.4 million, respectively, associated with derivative financial instruments that qualified for and were classified as cash flow hedges of

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

forecasted transactions that were subsequently de-designated, settled, or terminated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the years ended December 31, 2015 and 2014, unrealized commodity hedge gains of $1.5 million and losses of $0.2 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $45.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2015, will be reclassified from AOCI to earnings during the next 12 months.

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, 2015					
Interest rate contracts	$ 86.7	Interest expense	$(22.0)	Interest expense	$ 98.9
Commodity contracts	(24.2)	Commodity costs	32.9	Commodity costs	(4.1)
Total	$ 62.5		$ 10.9		$ 94.8
For the year ended December 31, 2014					
Interest rate contracts	$(163.4)	Interest expense	$(16.2)	Interest expense	$(100.1)
Commodity contracts	29.9	Commodity costs	(5.8)	Commodity costs	5.6
Total	$(133.5)		$(22.0)		$ (94.5)
For the year ended December 31, 2013					
Interest rate contracts	$ 251.0	Interest expense	$(29.8)	Interest expense	$ (21.5)
Commodity contracts	(16.5)	Commodity costs	2.7	Commodity costs	3.3
Total	$ 234.5		$(27.1)		$ (18.2)

(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.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges	
	2015	2014
	(in millions)	
Beginning Balance	$(211.4)	$ (76.6)
Other Comprehensive Income before reclassifications[1]	(155.7)	(155.9)
Amounts reclassified from AOCI[2][3]	(3.1)	21.2
Tax benefit (expense)	0.2	(0.1)
Net other comprehensive loss	$(158.6)	$(134.8)
Ending Balance	$(370.0)	$(211.4)

(1) Excludes NCI gains of $2.0 million and $6.3 million reclassified from AOCI at December 31, 2015 and 2014, respectively.

(2) Excludes NCI gains (losses) of $(7.8) million and $0.8 million reclassified from AOCI at December 31, 2015 and 2014, respectively.

(3) 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

	For the year ended December 31,		
	2015	2014	2013
		(in millions)	
Losses (gains) on cash flow hedges:			
Interest Rate Contracts[1]	$ 22.0	$16.2	$29.8
Commodity Contracts[2][3]	(25.1)	5.0	(2.7)
Total Reclassifications from AOCI	$ (3.1)	$21.2	$27.1

(1) Loss reported within ''Interest expense, net'' in the consolidated statements of income.

(2) Loss (gain) reported within ''Commodity costs'' in the consolidated statements of income.

(3) Excludes NCI gains (losses) of $(7.8) million and $0.8 million reclassified from AOCI for the years ending December 31, 2015 and 2014, respectively.

Effect of Derivative Instruments on Consolidated Statements of Income

		December 31,		
		2015	2014	2013
Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Earnings	Amount of Gain (Loss) Recognized in Earnings[1][2]		
			(in millions)	
Interest rate contracts	Interest expense[3]	$ —	$ —	$ —
Commodity contracts	Transportation and other services[4]	11.4	17.4	(3.0)
Commodity contracts	Commodity sales	(23.3)	23.7	(3.0)
Commodity contracts	Commodity sales – affiliate	(0.3)	0.3	—
Commodity contracts	Commodity costs[5]	65.7	136.8	(8.0)
Commodity contracts	Power	—	0.7	0.6
Total		$ 53.5	$178.9	$(13.4)

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

(2) 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.

(3) Includes settlement gains of $0 million, $0 million, and $0.2 million for the years ended December 31, 2015, 2014 and 2013, respectively.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

(4) Includes settlement gains of $26.9 million, $4.5 million, and $1.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

(5) Includes settlement gains (losses) of $96.3 million and $8.0 million and $(4.6) million for the years ended December 31, 2015, 2014, and 2013, respectively.

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 gross basis. However, the terms of the ISDA®, which govern 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. The effect of the rights of set-off are outlined below.

Offsetting of Financial Assets and Derivative Assets

	As of December 31, 2015				
	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[1]	Net Amount
			(in millions)		
Description:					
Derivatives	$163.6	$—	$163.6	$(41.5)	$122.1

	As of December 31, 2014				
	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[1]	Net Amount
			(in millions)		
Description:					
Derivatives	$279.1	$—	$279.1	$(91.8)	$187.3

(1) Includes $12.6 million and $28.4 million of cash collateral held at December 31, 2015 and December 31, 2014, respectively.

Offsetting of Financial Liabilities and Derivative Liabilities

	As of December 31, 2015				
	Gross Amount of Recognized Liabilities[1]	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[1]	Net Amount
			(in millions)		
Description:					
Derivatives	$(221.5)	$—	$(221.5)	$41.5	$(180.0)

	As of December 31, 2014				
	Gross Amount of Recognized Liabilities[1]	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[1]	Net Amount
			(in millions)		
Description:					
Derivatives	$(440.0)	$—	$(440.0)	$91.8	$(348.2)

(1) Includes $12.6 million and $28.4 million of cash collateral held at December 31, 2015 and 2014, respectively.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

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, 2015 and 2014. 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, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts	$—	$(157.5)	$ —	$(157.5)	$—	$(343.0)	$ —	$(343.0)
Commodity contracts:								
Financial	—	8.4	8.9	17.3	—	41.6	42.7	84.3
Physical	—	—	0.6	0.6	—	—	19.5	19.5
Commodity options	—	—	94.3	94.3	—	—	106.7	106.7
	—	(149.1)	103.8	(45.3)	—	(301.4)	168.9	(132.5)
Cash collateral				(12.6)				(28.4)
Total				$ (57.9)				$(160.9)

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, crude and power) 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 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. A change to the credit valuation adjustment would change the fair value of the positions in opposite directions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2015(2)	Valuation Technique	Unobservable Input	Range(1) Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 0.3	Market Approach	Forward Gas Price	2.27	3.07	2.64	MMBtu
NGLs	8.6	Market Approach	Forward NGL Price	0.16	0.93	0.41	Gal
Commodity Contracts – Physical							
Natural Gas	(2.5)	Market Approach	Forward Gas Price	2.08	3.44	2.33	MMBtu
Crude Oil	—	Market Approach	Forward Crude Price	26.50	38.41	37.29	Bbl
NGLs	3.1	Market Approach	Forward NGL Price	0.16	1.20	0.40	Gal
Commodity Options							
Natural Gas, Crude and NGLs	94.3	Option Model	Option Volatility	13%	74%	36%	
Total Fair Value	$103.8						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for natural gas; dollars per Gallon, or Gal, for NGLs; and dollars per barrel, or Bbl, for crude oil.

(2) Fair values include credit valuation adjustment losses of approximately $0.3 million.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Contract Type	Fair Value at December 31, 2014[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 0.6	Market Approach	Forward Gas Price	2.55	3.72	3.04	MMBtu
NGLs	42.1	Market Approach	Forward NGL Price	0.48	1.14	0.64	Gal
Commodity Contracts – Physical							
Natural Gas	1.5	Market Approach	Forward Gas Price	1.55	4.08	3.08	MMBtu
Crude Oil	(0.9)	Market Approach	Forward Crude Price	49.57	55.60	53.51	Bbl
NGLs	18.9	Market Approach	Forward NGL Price	0.06	1.21	0.54	Gal
Commodity Options							
Natural Gas, Crude and NGLs	106.7	Option Model	Option Volatility	19%	94%	36%	
Total Fair Value	$168.9						

(1) Prices are in dollars per MMBtu for natural gas, Gal for NGLs and Bbl for crude oil.

(2) Fair values include credit valuation adjustment losses of approximately $1.0 million.

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, 2015 to December 31, 2015. 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, 2015	$ 42.7	$ 19.5	$106.7	$ 168.9
Transfer in (out) of Level 3[1]	—	—	—	—
Gains or losses included in earnings:				
Reported in Commodity sales	—	(4.6)	—	(4.6)
Reported in Commodity costs	1.1	24.6	48.9	74.6
Gains or losses included in other comprehensive income:				
Reported in Other comprehensive income (loss), net of tax	0.4	—	—	0.4
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	2.0	2.0
Settlements[2]	(35.3)	(38.9)	(63.3)	(137.5)
Ending balance as December 31, 2015	$ 8.9	$ 0.6	$ 94.3	$ 103.8
Amounts reported in Commodity sales	$ —	$(23.6)	$ —	$ (23.6)
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets and liabilities still held at the reporting date:				
Reported in Commodity sales	$ —	$ (2.1)	$ —	$ (2.1)
Reported in Commodity costs	$ (1.1)	$ 2.3	$ 45.4	$ 46.6

(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.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at December 31, 2015 and 2014.

	At December 31, 2015						At December 31, 2014	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 2.52	$ 3.48	$ —	$ —	$ —	$(0.1)
	NGL	1,482,500	$20.77	$26.39	$ 0.2	$ (8.4)	$ —	$ —
	Crude Oil	475,950	$40.58	$77.56	$ —	$(17.5)	$ —	$(8.1)
Receive fixed/pay variable	NGL	1,958,600	$31.91	$22.62	$18.3	$ (0.2)	$9.3	$ —
	Crude Oil	791,270	$73.34	$41.13	$25.4	$ —	$9.1	$ —
Receive variable/pay variable . .	Natural Gas	5,124,000	$ 2.50	$ 2.49	$ 0.1	$ (0.1)	$0.5	$(0.3)
Physical Contracts								
Receive variable/pay fixed	NGL	180,000	$31.22	$32.31	$ —	$ (0.2)	$ —	$ —
	Crude Oil	55,166	$37.69	$40.61	$ —	$ (0.2)	$ —	$ —
Receive fixed/pay variable	NGL	838,119	$28.52	$26.54	$ 1.9	$ (0.2)	$ —	$ —
	Crude Oil	13,316	$36.40	$37.46	$ —	$ —	$ —	$ —
Receive variable/pay variable . .	Natural Gas	165,210,634	$ 2.30	$ 2.31	$ —	$ (2.8)	$0.7	$(0.4)
	NGL	10,638,085	$16.53	$16.37	$ 4.0	$ (2.4)	$ —	$ —
	Crude Oil	519,805	$37.16	$36.79	$ 0.7	$ (0.5)	$ —	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	76,530	$ 2.48	$ 2.97	$ —	$ —	$ —	$ —
	NGL	547,500	$17.38	$25.86	$ —	$ (4.5)	$ —	$ —
	Crude Oil	547,500	$46.47	$66.72	$ —	$(10.9)	$ —	$ —
Receive fixed/pay variable	NGL	622,500	$21.61	$16.28	$ 3.3	$ (0.1)	$0.7	$ —
	Crude Oil	547,500	$66.78	$46.47	$10.9	$ —	$0.8	$ —
Receive variable/pay variable . .	Natural Gas	8,050,000	$ 2.64	$ 2.60	$ 0.5	$ (0.2)	$ —	$ —
Physical Contracts								
Receive variable/pay variable . .	Natural Gas	2,187,810	$ 2.81	$ 2.79	$ 0.1	$ —	$0.2	$(0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable . .	Natural Gas	2,187,810	$ 2.98	$ 2.95	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable . .	Natural Gas	2,187,810	$ 3.14	$ 3.11	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable . .	Natural Gas	359,640	$ 3.45	$ 3.42	$ —	$ —	$ —	$ —

(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, 2015 and 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains of approximately $0.5 million and losses of approximately $0.5 million at December 31, 2015 and 2014, respectively, as well as cash collateral received.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2015 and 2014.

	At December 31, 2015						At December 31, 2014	
					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 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 2.49	$ 2.1	$ —	$ 1.0	$ —
	NGL	2,964,600	$39.29	$21.04	$54.4	$ —	$39.3	$ —
	Crude Oil	805,200	$75.91	$41.45	$27.7	$ —	$14.7	$ —
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 2.49	$ —	$ —	$ —	$(0.1)
	NGL	2,964,600	$45.09	$21.04	$ —	$(0.3)	$ —	$(3.2)
	Crude Oil	805,200	$86.68	$41.45	$ —	$ —	$ —	$(2.7)
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 2.49	$ —	$(2.1)	$ —	$(1.0)
	NGL	91,500	$39.06	$22.94	$ —	$(1.5)	$ —	$ —
Calls (purchased)	Natural Gas	1,647,000	$ 4.98	$ 2.49	$ —	$ —	$ 0.1	$ —
	NGL	91,500	$46.41	$22.94	$ —	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,277,500	$25.26	$22.13	$ 5.8	$ —	$ 1.2	$ —
	Crude Oil	547,500	$63.00	$46.47	$10.0	$ —	4.1	$ —
Calls (written)	NGL	1,277,500	$29.46	$22.13	$ —	$(0.8)	$ —	$(0.7)
	Crude Oil	547,500	$71.45	$46.47	$ —	$(0.6)	$ —	$(3.3)

(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, 2015 and 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment losses of approximately $0.4 million and $0.7 million at December 31, 2015 and 2014, respectively, as well as cash collateral received.

Fair Value Measurements of Interest Rate Derivatives

We enter into interest rate swaps, caps and derivative financial instruments with similar characteristics to manage the cash flow associated with future interest rate movements on our indebtedness. The following table provides information about our current interest rate derivatives for the specified periods.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value[2] December 31, 2015	Fair Value[2] December 31, 2014
			(dollars in millions)		
Contracts maturing in 2016					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 90	0.55%	$ —	$ (0.1)
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$500	2.21%	$ (7.0)	$(12.9)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$810	2.24%	$ (6.6)	$ (1.3)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$620	2.96%	$ (6.0)	$ (3.3)
Contracts settling prior to maturity					
2016 – Pre-issuance Hedges	Cash Flow Hedge	$500	4.21%	$(80.4)	$(63.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	$500	3.69%	$(49.2)	$(36.0)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$350	3.08%	$(12.2)	$ (4.9)

(1) Interest rate derivative contracts are based on the one-month or three-month LIBOR.

(2) The fair value is determined from quoted market prices at December 31, 2015 and 2014, 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 adjustment gains of approximately $3.9 million and $37.4 million at December 31, 2015 and 2014, respectively.

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 franchise tax laws of the State of Texas that apply to entities organized as partnerships. Our income tax expense is based upon many but not all items included in net income.

We computed our income tax expense by applying a Texas franchise tax rate to modified gross margin. For the years ended December 31, 2015, 2014 and 2013, our Texas franchise tax rate was 0.4%, 0.4% and 0.5%, respectively. Our income tax expense is summarized below:

	2015	2014	2013
		(in millions)	
Current state	$ 5.6	$5.5	$ 4.3
Deferred state	(0.7)	4.1	14.4
Total income tax expense	$ 4.9	$9.6	$18.7

Our effective tax rate is calculated by dividing the income tax expense by the pretax net book income or loss. The income base for calculating our income tax expense is modified gross margin for Texas rather than pretax net book income or loss. As a result, this difference is the only reconciling item between the statutory and effective income tax rate. Our effective tax rate for the years ended December 31, 2015, 2014 and 2013, is as follows:

	2015	2014	2013
		(in millions)	
Income before income tax expense	$459.2	$749.6	$179.1
State income tax expense	$ 4.9	$ 9.6	$ 18.7
Effective income tax rate	1.1%	1.3%	10.4%

The Texas Franchise Tax Reduction Act of 2015 was signed into law on June 15, 2015. The law applies to original reports filed on or after January 1, 2016, and permanently reduces Texas franchise tax rates. Specifically, the general 1.0% rate will be reduced to 0.75%. As a result of this change, we have recorded a reduction in our deferred income tax payable reflected in ''Other long-term liabilities'' on our consolidated statement of financial position of approximately $5.4 million at December 31, 2015.

At December 31, 2015 and 2014, we included a current income tax payable of $1.1 million and $1.5 million, respectively, in ''Property and other taxes payable'' on our consolidated statements of financial position. In addition, at December 31, 2015 and 2014, we included a deferred income tax payable of $20.9 million and $21.7 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. 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,	
	2015	2014
	(in millions)	
Net book basis of assets in excess of tax basis	$(20.9)	$(21.5)
Net book losses on derivatives not recognized for tax purposes	—	(0.2)
Net deferred tax liability	$(20.9)	$(21.7)

15. INCOME TAXES – (continued)

Accounting for Uncertainty in Income Taxes

The following is a reconciliation of our beginning and ending balance of unrecognized tax benefits in millions:

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at January 1	$33.2	$29.8	$21.8
Additions for tax positions taken in current period	3.3	3.4	8.0
Unrecognized tax benefits at December 31	$36.5	$33.2	$29.8

As of December 31, 2015, 2014 and 2013, the entire balance of unrecognized tax benefits would favorably affect our effective tax rate in future periods if recognized. It is reasonably possible that our liability for unrecognized tax benefits will increase by $2.6 million during the next twelve months. We also recognized interest accrued related to unrecognized tax benefits and penalties as income tax expense. As of December 31, 2015, we have accrued penalties of $1.2 million and interest of $0.8 million. Furthermore, we recognize accrued interest income related to unrecognized tax benefits in interest income when the related unrecognized tax benefits are recognized. As such, at December 31, 2015 and 2014, $0.8 million and $0.7 million of accrued interest income, respectively, has not been included in the balance of unrecognized tax benefits.

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ended December 2014, 2013 and 2012.

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 and is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into two distinct operating segments:

- Liquids; and
- Natural Gas.

During the first quarter of 2014, we changed our reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment called ‘‘Natural Gas.’’ There was no change to the Liquids segment.

This change was a result of our reorganization resulting from the MEP Offering, which prompted management to reassess the presentation of our reportable segments considering the financial information available and evaluated regularly by our Chief Operating Decision Maker. The new segment is consistent with how management makes resource allocation decisions and evaluates performance, and furthers the achievement of our long-term objectives. Financial information for the year ended December 31, 2013, has been restated to reflect the change in reporting segments.

16. SEGMENT INFORMATION – (continued)

The following tables present certain financial information relating to our business segments and corporate activities:

	As of and for the year ended December 31, 2015			
	Liquids	Natural Gas	Corporate[(1)]	Total
	(in millions)			
Operating revenues:[(2)]				
Commodity sales	$ —	$2,646.4	$ —	$ 2,646.4
Transportation and other services	2,303.4	196.3	—	2,499.7
	2,303.4	2,842.7	—	5,146.1
Operating expenses:				
Commodity costs	—	2,372.9	—	2,372.9
Environmental costs, net of recoveries	3.1	—	—	3.1
Operating and administrative	605.9	351.0	14.4	971.3
Power	259.5	—	—	259.5
Goodwill impairment	—	246.7	—	246.7
Asset impairment	62.5	12.3	—	74.8
Depreciation and amortization	378.4	157.8	—	536.2
	1,309.4	3,140.7	14.4	4,464.5
Operating income (loss)	994.0	(298.0)	(14.4)	681.6
Interest expense, net	—	—	(322.0)	(322.0)
Allowance for equity used during construction	—	—	70.3	70.3
Other income	—	29.3[(3)]	—	29.3
Income (loss) before income tax expense	994.0	(268.7)	(266.1)	459.2
Income tax expense	—	—	(4.9)	(4.9)
Net income (loss)	994.0	(268.7)	(271.0)	454.3
Less: Net income attributable to:				
Noncontrolling interest	—	—	221.1	221.1
Series 1 preferred unit distributions	—	—	90.0	90.0
Accretion of discount on Series 1 preferred units	—	—	11.2	11.2
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 994.0	$ (268.7)	$(593.3)	$ 132.0
Total assets	$13,484.1	$5,142.3[(4)]	$ 189.4	$18,815.8
Capital expenditures (excluding acquisitions)	$ 1,975.9	$ 173.6	$ 4.8	$ 2,154.3

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) There were no intersegment revenues for the year ended December 31, 2015.

(3) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

(4) Totals assets for our Natural Gas segment includes $372.3 million for our equity investment in the Texas Express NGL system.

16. SEGMENT INFORMATION – (continued)

	As of and for the year ended December 31, 2014			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:[2]				
Commodity sales	$ —	$5,693.9	$ —	$ 5,693.9
Transportation and other services	2,070.4	200.4	—	2,270.8
	2,070.4	5,894.3	—	7,964.7
Operating expenses:				
Commodity costs	—	5,145.9	—	5,145.9
Environmental costs, net of recoveries	97.3	—	—	97.3
Operating and administrative	500.8	423.0	10.6	934.4
Power	226.6	—	—	226.6
Asset impairment	—	15.6	—	15.6
Depreciation and amortization	306.8	151.4	—	458.2
	1,131.5	5,735.9	10.6	6,878.0
Operating income (loss)	938.9	158.4	(10.6)	1,086.7
Interest expense, net	—	—	(403.2)	(403.2)
Allowance for equity used during construction	—	—	57.2	57.2
Other income (expense)	—	13.2[3]	(4.3)	8.9
Income (loss) before income tax expense	938.9	171.6	(360.9)	749.6
Income tax expense	—	—	(9.6)	(9.6)
Net income (loss)	938.9	171.6	(370.5)	740.0
Less: Net income attributable to:				
Noncontrolling interest	—	—	263.3	263.3
Series 1 preferred unit distributions	—	—	90.0	90.0
Accretion of discount on Series 1 preferred units	—	—	14.9	14.9
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 938.9	$ 171.6	$(738.7)	$ 371.8
Total assets	$11,871.2	$5,633.5[4]	$ 242.2	$17,746.9
Capital expenditures (excluding acquisitions)	$ 2,563.4	$ 230.0	$ 6.0	$ 2,799.4

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) There were no intersegment revenues for the year ended December 31, 2014.

(3) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

(4) Totals assets for our Natural Gas segment includes $380.6 million for our equity investment in the Texas Express NGL system.

16. SEGMENT INFORMATION – (continued)

	As of and for the year ended December 31, 2013			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:[2]				
Commodity sales	$ —	$5,368.5	$ —	$ 5,368.5
Transportation and other services	1,519.9	228.7	—	1,748.6
	1,519.9	5,597.2	—	7,117.1
Operating expenses:				
Commodity costs	—	4,948.9	—	4,948.9
Environmental costs, net of recoveries	273.7	—	—	273.7
Operating and administrative	461.0	449.8	7.6	918.4
Power	147.7	—	—	147.7
Depreciation and amortization	244.9	143.1	—	388.0
	1,127.3	5,541.8	7.6	6,676.7
Operating income (loss)	392.6	55.4	(7.6)	440.4
Interest expense, net	—	—	(320.4)	(320.4)
Allowance for equity used during construction	—	—	43.1	43.1
Other income (expense)	—	(1.5)[3]	17.5[4]	16.0
Income (loss) before income tax expense	392.6	53.9	(267.4)	179.1
Income tax expense	—	—	(18.7)	(18.7)
Net income (loss)	392.6	53.9	(286.1)	160.4
Less: Net income attributable to:				
Noncontrolling interest	—	—	88.3	88.3
Series 1 preferred unit distributions	—	—	58.2	58.2
Accretion of discount on Series 1 preferred units	—	—	9.2	9.2
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 392.6	$ 53.9	$(441.8)	$ 4.7
Total assets	$9,268.9	$4,635.1[5]	$ 997.5	$14,901.5
Capital expenditures (excluding acquisitions)	$2,330.7	$ 251.3	$ 18.8	$ 2,600.8

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) There were no intersegment revenues for the year ended December 31, 2013.

(3) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system, which began recognizing operating costs during the fourth quarter of 2013.

(4) Other income (expense) for our Corporate segment includes a gain of $17.1 million from the El Dorado storage facility sale in November of 2013.

(5) Totals assets for our Natural Gas segment includes $371.3 million for our equity investment in the Texas Express NGL system.

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2015 accounted for approximately 10.4% of our third-party revenues for the year ended December 31, 2015. No other customers accounted for 10% or more of our third-party revenues during any of the three years ended December 31, 2015, 2014, and 2013.

17. REGULATORY MATTERS

Regulatory Assets and Liabilities

Due to over or under recovery adjustments made in accordance with the FERC's authoritative guidance and our cost-of-service recovery model, we recognize assets and liabilities for regulatory purposes. The assets and liabilities that we recognize for regulatory purposes are recorded on a net basis in ''Other current assets'' or ''Accounts payable and other,'' respectively, on our consolidated statements of financial position. These regulatory assets and liabilities are amortized on a straight-line basis over a one-year recovery period. Our over and under recovery revenue adjustments and net regulatory asset amortization for the twelve month periods ended December 31, 2015, 2014, and 2013 are as follows:

	For the year ended December 31,		
	2015	2014	2013
		(in millions)	
Net regulatory asset (liability) balance at beginning of period	$ 6.0	$ 7.7	$(15.3)
Current year (over)/under recovery adjustments	29.9	6.0	7.7
Amortization of prior year regulatory (asset)/liability	(6.0)	(7.7)	15.3
Net regulatory asset (liability) balance at end of period	$29.9	$ 6.0	$ 7.7

Other Contractual Obligations

Southern Access Pipeline

We have entered into certain contractual obligations with our customers on the Southern Access Pipeline in which a portion of the revenue earned on volumes above certain predetermined shipment levels, or qualifying volumes, are returned to the shippers through future rate adjustments. We record the liabilities associated with this contractual obligation in ''Accounts payable and other,'' on our consolidated statements of financial position. The amortization for this contractual obligation reflects the related transportation rate adjustment in the subsequent year. At December 31, 2015 and 2014 we had no qualifying volume liabilities related to the Southern Access Pipeline on our consolidated statements of financial position.

For the years ended December 31, 2013 and 2012, we incurred liabilities for contractual obligations with our customers on the Southern Access Pipeline related to qualifying volumes. As a result, in 2013 and 2012, we recorded a liability for the contractual amounts due back to our shippers with the corresponding amount as a reduction to revenue. We amortized the liability on a straight line basis as an adjustment to revenue in the following year. For the years ended December 31, 2014 and 2013, we amortized through revenue $6.1 million and $6.3 million of qualifying volume liabilities on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position. There was no amortization for qualifying volume liabilities related to our Southern Access Pipeline for the twelve months ended 2015.

Alberta Clipper Pipeline

A portion of the rates we charge our customers includes an estimate for annual property taxes. If the estimated property tax we collect from our customers is higher or lower than the actual property tax imposed, we are contractually obligated to refund to our customers or entitled to collect from our customers 50% of the property tax over or under recovery, respectively. At December 31, 2015 and 2014, we recorded a $0.8 million property tax under recovery asset and a $5.9 million property tax over recovery liability, respectively, in our consolidated statements of financial position in relation to our Alberta Clipper Pipeline.

For the years ended December 31, 2014, 2013 and 2012, we also incurred liabilities for contractual obligations with our customers on the Alberta Clipper Pipeline related to property taxes. As a result, in 2014, 2013 and 2012, we recorded a liability for the contractual amounts due back to our shippers with the corresponding amount as a reduction to revenue. We amortized the liability on a straight line basis as an adjustment to revenue in the following year. For the years ended December 31, 2015, 2014 and 2013, we amortized through revenue $5.9 million,

17. REGULATORY MATTERS – (continued)

$6.9 million, and $6.0 million of property tax over recovery liabilities, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include allowance for equity costs during construction, or AEDC. In connection with construction of the Eastern Access Projects, Line 6B 75-mile Replacement and Mainline Expansion projects, we recorded $70.3 million, $57.2 million, and $43.1 million of ''Allowance for equity used during construction'' on our consolidated statements of income at December 31, 2015, 2014 and 2013, respectively, with a corresponding amount to ''Property, plant and equipment, net'' on our consolidated statements of financial position for the respective periods.

18. SUPPLEMENTAL CASH FLOWS INFORMATION

	For the year ended December 31,		
	2015	2014	2013
		(in millions)	
Cash Paid during the year for:			
Interest (net of capitalization)	$379.5	$332.4	$342.3
Income taxes	$ 1.8	$ 1.5	$ 2.5

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,		
	2015	2014	2013
		(in millions)	
Additions to property, plant and equipment	$2,116.8	$2,933.6	$2,409.9
Increase (decrease) in construction payables	37.5	(141.0)	190.9
Capital leases	—	6.8	—
Total capital expenditures	$2,154.3	$2,799.4	$2,600.8

19. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. In July 2015, the FASB delayed the effective date of the new revenue standard by one year. This accounting update is effective for annual and interim periods beginning on or after December 15, 2017, and may be applied on either a full or modified retrospective basis. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements.

Consolidation

In February 2015, the FASB issued Accounting Standards Update No. 2015-02, which addresses concerns about the current accounting for consolidation of certain legal entities. It makes targeted amendments to the current consolidation guidance and ends the deferral granted to certain entities from applying the variable interest entity, or VIE, guidance. Among other things, the amended standard revised the consolidation model and guidance for limited partnerships, which included the elimination of the presumption that a general partner should consolidate a limited partnership and the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships. This accounting update is effective for annual periods, and for interim periods within those annual periods, beginning after December 15, 2015. Early adoption is permitted, and the new standard may be adopted either retrospectively or using a modified retrospective approach. We do not

19. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED – (continued)

anticipate that our ultimate consolidation conclusions for non-wholly-owned subsidiaries will change upon adoption of the revised guidance. However, we believe that additional VIE disclosures will be required.

20. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
	(in millions, except per unit amounts)				
2015 Quarters					
Operating revenue	$1,428.6	$1,313.1	$1,267.7	$1,136.7	$5,146.1
Operating expense[(1)]	$1,189.0	$1,322.7	$1,012.9	$ 939.9	$4,464.5
Operating income (loss)	$ 239.6	$ (9.6)	$ 254.8	$ 196.8	$ 681.6
Net income (loss)	$ 217.8	$ (60.5)	$ 184.5	$ 112.5	$ 454.3
Net income attributable to noncontrolling interest	$ 51.3	$ 10.0	$ 77.8	$ 82.0	$ 221.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 140.1	$ (97.1)	$ 82.1	$ 6.9	$ 132.0
Net income (loss) per common unit and i-unit (basic and diluted)	$ 0.26	$ (0.44)	$ 0.07	$ (0.14)	$ (0.25)
2014 Quarters					
Operating revenue	$2,079.6	$1,871.1	$1,942.3	$2,071.7	$7,964.7
Operating expense	$1,864.9	$1,690.2	$1,701.9	$1,621.0	$6,878.0
Operating income	$ 214.7	$ 180.9	$ 240.4	$ 450.7	$1,086.7
Net income	$ 155.7	$ 112.5	$ 117.5	$ 354.3	$ 740.0
Net income attributable to noncontrolling interest	$ 36.3	$ 42.4	$ 70.7	$ 113.9	$ 263.3
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 93.3	$ 43.9	$ 20.5	$ 214.1	$ 371.8
Net income (loss) per common unit and i-unit (basic and diluted)	$ 0.18	$ 0.02	$ (0.04)	$ 0.51	$ 0.67

(1) Second quarter 2015 operating expenses were impacted by a goodwill impairment of $246.7 million. For more information, refer to Note 8. *Goodwill*.

21. SUBSEQUENT EVENTS

Distribution to Partners

On January 29, 2016, the board of directors of Enbridge Management declared a distribution payable to our partners on February 12, 2016. The distribution was paid to unitholders of record as of February 5, 2016, of our available cash of $259.6 million at December 31, 2015, or $0.5830 per limited partner unit. Of this distribution, $216.0 million was paid in cash, $42.7 million was distributed in i-units to our i-unitholder and $0.9 million was retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series EA Interests

On January 29, 2016, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP paid the entire $79.2 million distribution to us.

21. SUBSEQUENT EVENTS – (continued)

Distribution to Series ME Interests

On January 29, 2016, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series ME interests, declared a distribution payable to the holders of the Series ME general and limited partner interests. The OLP paid the entire $40.8 million distribution to us.

Distribution from MEP

On January 28, 2016, 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 to their partners on February 12, 2016. The distribution was paid to unitholders of record as of February 5, 2016, of MEP's available cash of $16.5 million at December 31, 2014, or $0.3575 per limited partner unit. MEP paid $7.6 million to their public Class A common unitholders, while $8.9 million in the aggregate was paid to us with respect to our Class A common units, subordinated units and to Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On January 28, 2016, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of February 5, 2016. Midcoast Operating paid $25.9 million to us and $27.6 million to MEP.

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, 2015. 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 Partnership's internal control over financial reporting includes policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect transactions and dispositions of assets of the Partnership;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with the authorizations of the Partnership's management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, the Partnership's internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with our policies or procedures may deteriorate.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2015, with the participation of our principal executive and principal financial officers, based on the framework established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2015.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in Item 8. *Financial Statements and Supplementary Data*.

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 months ended December 31, 2015.

Item 9B. Other Information

None.

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 the General Partner and of Enbridge Management as the delegate of the General Partner under a delegation of control agreement among us, the General Partner and Enbridge Management. All directors of the General Partner are elected annually and may be removed by Enbridge (U.S.) Inc., as the sole shareholder of the General Partner, an indirect and wholly-owned subsidiary of Enbridge. All directors of Enbridge Management were elected and may be removed by the General Partner, as the sole holder of Enbridge Management's voting shares. All officers of the General Partner and Enbridge Management serve at the discretion of the boards of directors of the General Partner and Enbridge Management, respectively. All directors and officers of the General Partner hold identical positions in Enbridge Management.

Name	Age	Position
Jeffrey A. Connelly	69	Director and Chairman of the Board
J. Richard Bird	66	Director
J. Herbert England	69	Director
C. Gregory Harper	51	Director and Executive Vice President — Gas Pipelines & Processing
D. Guy Jarvis	52	Director and Executive Vice President — Liquids Pipelines
Mark A. Maki	51	Director and President and Principal Executive Officer
Dan A. Westbrook	63	Director
John K. Whelen	56	Director
E. Chris Kaitson	59	Vice President — Law and Assistant Corporate Secretary
Stephen J. Neyland	48	Vice President — Finance
Bradley F. Shamla	47	Vice President — Liquids Pipelines, Operations
Leo J. Golden	49	Vice President — Major Projects
Cynthia L. Hansen	51	Senior Vice President — Liquids Pipelines, Operations
Noor S. Kaissi	43	Controller
Jonathan N. Rose	48	Treasurer
Allan M. Schneider	57	Vice President, Regulated Engineering and Operations
Leon A. Zupan	60	Executive Vice President — Liquids Pipelines, Operations

DIRECTORS AND NAMED EXECUTIVE OFFICERS

Jeffrey A. Connelly

Jeffrey A. Connelly was elected as Chairman of the Board of Directors, or the Board, in July 2012 and as a director of the General Partner and Enbridge Management in January 2003. Previously, Mr. Connelly served as Chairman of the Audit, Finance & Risk Committee of the General Partner and Enbridge Management. Mr. Connelly also served as Executive Vice President, Senior Vice President and Vice President of the Coastal Corporation from 1988 to 2001.

Mr. Connelly brings significant financial experience to our Board because of his experience as the former Treasurer and other executive roles with Coastal Corporation, a former Fortune 500 Company whose principal business segments included gathering, processing, transmission, storage and distribution of natural gas; oil refining and marketing; oil exploration and production; electric power production; and coal mining. He also served as the chief executive officer for several wholly-owned Coastal subsidiaries.

J. Richard Bird

J. Richard Bird was elected a director of the General Partner and for Enbridge Management in October 2012. He retired from Enbridge in early 2015, having served as Executive Vice President, Chief Financial Officer and Corporate Development, and various other roles, including: Executive Vice President Liquids Pipelines, Senior Vice President Corporate Planning and Development, and Vice President and Treasurer during his tenure with Enbridge which began in 1995. Mr. Bird serves on the Board of Directors or Trustees of Enbridge Pipelines Inc., Enbridge Income Fund Holdings Inc., Gaz Metro Inc. and Bird Construction Company Inc. He is a member of the Board of Directors of the Alberta Investment Management Company and chairman of its audit committee. Mr. Bird is also a member of the Investment Committee of the University of Calgary Board of Governors. He was named Canada's CFO of the Year for 2010. He holds a Bachelor of Arts degree from the University of Manitoba, and a Masters of Business Administration and PhD from the University of Toronto and has completed the Advanced Management Program at Harvard Business School.

Through his long career in the energy industry and his financial expertise, Mr. Bird provides significant experience to the Boards of the General Partner and Enbridge Management.

J. Herbert England

J. Herbert England was elected a director of the General Partner and Enbridge Management in July 2010 and was appointed as the Chairman of the Audit, Finance & Risk Committee of the General Partner and Enbridge Management in July 2012. Mr. England also serves on the Enbridge board of directors, for whom he also is Chairman of the Audit, Finance & Risk Committee, and on the board of directors and the audit committee of FuelCell Energy, Inc. In 2013, he was appointed to the board of directors of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P., for whom he also serves as Chairman of the Audit, Finance & Risk Committee. 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 a wide range of financial executive experience because of his previous positions, as well as his service with other public company audit committees.

C. Gregory Harper

C. Gregory Harper was appointed to the board of directors of our General Partner and the board of directors of Enbridge Management on January 30, 2014, and he was elected Executive Vice President — Gas Pipelines & Processing of each of the General Partner and Enbridge Management on April 30, 2014. Mr. Harper was also appointed to the board of directors of Midcoast Holdings, L.L.C. on January 30, 2014, principal executive officer on February 28, 2014 and on December 31, 2014, he was elected as President of Midcoast Holdings, L.L.C. Mr. Harper also was appointed as President, Gas Pipelines and Processing for Enbridge effective January 30, 2014. He has served on the board of directors of Sprague Operating Resources L.L.C. since October 2013. Prior to joining Enbridge, Mr. Harper served as the Senior Vice President, Midstream for Southwestern Energy 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 was Group Vice President of Spectra Energy Corp., and he was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper served as 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, L.L.C. from March 2002 until January 2003. He served on the Board of Directors and as Chairman of the Interstate Natural Gas Association of America for 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.

D. Guy Jarvis

D. Guy Jarvis was appointed Executive Vice President — Liquids Pipelines and a director of the General Partner and Enbridge Management on March 1, 2014. Mr. Jarvis was appointed President of the Liquids Pipelines division of Enbridge on March 1, 2014, assuming responsibility for all of Enbridge's crude oil and liquids pipeline businesses across North America. Prior to this, he was Chief Commercial Officer, Liquids Pipelines from October 2013 to March 2014. From September 2011 to October 2013, Mr. Jarvis served as President of Enbridge Gas Distribution, providing overall leadership to Enbridge Gas Distribution, Canada's largest natural gas utility, as well as Enbridge Gas New Brunswick, Gazifère and St. Lawrence Gas. Previously at Enbridge Pipelines Inc., Mr. Jarvis served as Senior Vice President, Investor Relations & Enterprise Risk; Senior Vice President, Business Development from March 2008 to October 2010; Vice President, Upstream Development for Enbridge Pipelines Inc.; and Vice President, Gas Services.

Mr. Jarvis joined Enbridge in 2000 and brings to the board over a quarter century of experience in the oil and gas business, the bulk of which relates to energy marketing and business development activities.

Mark A. Maki

Mark A. Maki was appointed President and Principal Executive Officer of the General Partner and Enbridge Management on January 30, 2014 and has served as a director of both companies since October 2010. Mr. Maki is also a director and Senior Vice President of Midcoast Holdings, L.L.C. Previously, Mr. Maki served as President of Enbridge Management and Senior Vice President of the General Partner from October 2010 to January 2014 and he served Enbridge in the functional title of Acting President, Gas Pipelines during 2013. Mr. Maki also previously served Midcoast Holdings, L.L.C. as Principal Executive Officer until February, 2014 and previously served as Vice President — Finance of the General Partner and Enbridge Management from July 2002. Prior to that time, Mr. Maki served as Controller of the General Partner and Enbridge Management from June 2001, and prior to that, as Controller of Enbridge Pipelines from September 1999.

Mr. Maki brings almost thirty years of oil and gas experience to the board, having joined Enbridge in 1986 and progressing through a series of accounting and financial roles of increasing responsibility during his tenure with Enbridge in the United States and Canada. Through his broad range of domestic and Canadian experience in the pipeline industry, Mr. Maki provides our Board with financial expertise, leadership skills in our industry and knowledge of our local community and business environment.

Dan A. Westbrook

Dan A. Westbrook was elected a director of the General Partner and Enbridge Management in October 2007 and serves on the Audit, Finance & Risk Committee of the General Partner and Enbridge Management, as well as 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. and a director and chairman of the board of Midcoast Holdings, L.L.C., the general partner of Midcoast Energy Partners, L.P., and serves on their Audit Finance & Risk Committee. 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 as 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 provided 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 our Board with extensive industry experience, leadership skills, international and petroleum development experience, as well as knowledge of our business environment.

John K. Whelen

John K. Whelen was elected a director of the General Partner and Enbridge Management on October 31, 2014. Mr. Whelen also serves Enbridge as Executive Vice President and Chief Financial Officer since October 15, 2014, and as such leads the financial reporting function, and tax and treasury functions for Enbridge. Prior to this, from July 2014, to October 2014, Mr. Whelen was Senior Vice President, Finance for Enbridge and from April 2011 to July 2014 he was Senior Vice President and Controller. From September 2006 to April 2011, Mr. Whelen was Senior Vice President, Corporate Development for Enbridge. Additionally, Mr. Whelen has served as the chief financial officer, and then president of Enbridge Income Fund. Mr. Whelen joined Enbridge in 1992 as Manager of Treasury at what has become Enbridge Gas Distribution and has held a series of executive positions during his tenure with Enbridge.

Mr. Whelen brings to our Board his broad experience in capital markets as well as treasury, risk management, corporate planning and development, and financial reporting.

E. Chris Kaitson

E. Chris Kaitson was appointed Vice President — Law and Assistant Secretary of the General Partner and Enbridge Management in May 2007. His title was changed to Vice President — Law and Assistant Corporate

Secretary in April 2014. Mr. Kaitson also serves as Vice President — Law and Assistant Corporate Secretary of Midcoast Holdings, L.L.C., general partner of MEP. He also currently serves as Deputy General Counsel of Enbridge. Prior to that, he was Assistant General Counsel and Assistant Secretary of the General Partner and Enbridge Management from July 2004. He served as Corporate Secretary of the 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.

Stephen J. Neyland

Stephen J. Neyland was appointed Vice President — Finance of the General Partner and Enbridge Management in October 2010. Mr. Neyland also serves as Vice President — Finance of Midcoast Holdings, L.L.C., general partner of MEP, since its formation in May 2013. Mr. Neyland was previously Controller of the General Partner and Enbridge Management effective September 2006. Prior to these appointments, he served the General Partner 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.

Bradley F. Shamla

Bradley F. Shamla was appointed Vice President — U.S. Operations, Liquids Pipelines of the General Partner and Enbridge Management in April 2013. He previously served Enbridge as Vice President, Market Development since October 2010. Mr. Shamla was previously a senior director in the Business Development Group of Enbridge since 2008 and before that he was general manager in the Liquids Pipelines Operations Group, having joined Enbridge in 1991 and worked in a number of areas, including Operations, Engineering and Administration, both in the U.S. and Canada.

OTHER EXECUTIVE OFFICERS

Leo J. Golden was appointed Vice President — Major Projects of the General Partner and Enbridge Management on April 30, 2015. Since July 2014 he also serves Enbridge as a Vice President responsible for the execution of Renewables, Power and Gas Processing projects in both Canada and the U.S. From November 2011 to July 2014, Mr. Golden served Enbridge as Vice President, Major Projects Execution for certain subsidiaries. From April 2008 and November 2011, he was Vice President of Pipeline and Green Energy Projects and Vice President of the Alberta Clipper Project for certain Enbridge subsidiaries. Mr. Golden has served Enbridge in many capacities for over 25 years, having joined in September 1990. His roles have included Director and Project Director of several Enbridge projects and areas, including Alberta Clipper, Shipper Services, Oil Sands and Acquisitions, Rates Assistant, Rates Analyst, Planning Analyst, Energy Analyst, and Manager of Business Development. In 1989, prior to joining Enbridge, Mr. Golden was a policy analyst with the Vancouver Stock Exchange.

Cynthia L. Hansen was appointed Senior Vice President — Liquids Pipelines of the General Partner and Enbridge Management effective January 1, 2015. Ms. Hansen also serves Enbridge as Senior Vice President — Operations, Liquids Pipelines since December 2014. Ms. Hansen joined Enbridge in 1999 and previously served Enbridge as Senior Vice President–Enterprise Safety and Operational Reliability from February 2013 to December 2014 prior to which she was Vice President — System Performance & Solutions for Enbridge Pipelines Inc. from July 2012 to January 2013. She was also Vice President Canadian Operations for Enbridge Pipelines Inc. from November 2010 to July 2012 and Vice President Finance from March 2007 to November 2010. Prior to joining Enbridge, Ms. Hansen was a director at PricewaterhouseCoopers.

Noor S. Kaissi was appointed Controller of the General Partner and Enbridge Management in July 2013. Ms. Kaissi also serves as Controller of Midcoast Holdings, L.L.C., general partner of MEP. Ms. Kaissi previously served as Chief Auditor and in other managerial roles of the General Partner with responsibility for financial accounting, internal audit and controls from June 2005.

Jonathan N. Rose was appointed Treasurer of the General Partner and Enbridge Management in 2014. Mr. Rose also serves as Treasurer of Midcoast Holdings, L.L.C., general partner of MEP. Additionally, Mr. Rose serves Enbridge in the role of Director, Treasury since 2014. Mr. Rose's prior roles with Enbridge include Director, Business Development of Enbridge Pipelines Inc. from April 2010 to March 2014 and Treasurer of the General Partner and Enbridge Management from January 2008 to April 2010. He was previously Assistant Treasurer of the General Partner and Enbridge Management from July 2005 to January 2008. Mr. Rose was also a Director, Finance of Enbridge, a position he held from October 2007 to 2010, prior to which he was Manager, Finance from 2004 to December 2008. Prior to that Mr. Rose was a Vice President with Citigroup Global Corporate and Investment Bank from 2001 to 2004.

Allan M. Schneider was appointed Vice President, Regulated Engineering and Operations of the General Partner and Enbridge Management in October 2007. Mr. Schneider also serves as Vice President — Regulated Engineering and Operations of Midcoast Holdings, L.L.C., general partner of MEP. 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.

Leon A. Zupan currently serves the General Partner and Enbridge Management as Executive Vice President — Liquids Pipelines, Operations since April 2014. Previously, from April 2013 to April 2014, he served as Executive Vice President. In April 2013, he resigned as a director and as Executive Vice President — Gas Pipelines of the General Partner and Enbridge Management, positions which he held since April 2012, to accept a new position with Enbridge as Chief Operating Officer of Liquids Pipelines. Prior to April 2012, he had served the General Partner and Enbridge Management as Vice President — Operations since 2004. Prior to May of 2013, he served Enbridge as Senior Vice President — Gas Pipelines, overseeing Enbridge's U.S. and Canadian gas pipelines businesses from February 2012 to April 2013. Prior to that, Mr. Zupan had served Enbridge as Vice President — Operations since 2004. Mr. Zupan joined Enbridge in 1987 and has experience across a range of businesses.

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 United States Securities and Exchange Commission, or 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 inquiries made to our directors and executive officers, we believe that all filings required to be made under Section 16(a) during 2015 were timely made.

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 the General Partner. Because we are a controlled company, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the 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 was provided as required to the NYSE on March 11, 2015.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

We have adopted a Code of Ethics applicable to our senior officers, including the principal executive officer, principal financial officer and principal accounting officer of Enbridge Management. A copy of the Code of Ethics for Senior Financial Officers is available on our website at *www.enbridgepartners.com* and is included herein as Exhibit 14.1. 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 Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

We also have a Statement of Business Conduct applicable to all of our employees, officers and directors. A copy of the Statement of Business Conduct is available on our website at *www.enbridgepartners.com*. We post on our website any amendments to or waivers of our Statement of Business Conduct, 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 Enbridge 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.enbridgepartners.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 Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

AUDIT, FINANCE & RISK COMMITTEE

Enbridge Management has an Audit, Finance & Risk Committee, referred to as the ''Audit Committee,'' comprised of three 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. Mr. England is chairman of the Audit Committee. The members of the Audit Committee are Jeffrey A. Connelly, J. Herbert England and Dan A. Westbrook. Rebecca B. Roberts also was a member of the Audit Committee until her resignation as a director on March 19, 2015. 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.enbridgepartners.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 Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Enbridge Management's Board of Directors has determined that Mr. England and Mr. Connelly 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 Enbridge Management, FuelCell Energy, Inc., Midcoast Holdings, L.L.C., 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 of Midcoast Holdings, L.L.C. determined that Mr. England's simultaneous service on such audit committees does not impair his ability to effectively serve on the Audit Committee.

Enbridge Management'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 Enbridge Energy Partners L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of Enbridge Management meet at regularly scheduled executive sessions without management. Jeffrey A. Connelly 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, Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

General

We are an MLP and do not employ directly any employees nor do we have executive officers or directors. We are managed by Enbridge Management, a delegate of our General Partner, and the Named Executive Officers, or NEOs, are executive officers of Enbridge Management and our General Partner. Similarly, the directors are members of the boards of directors of Enbridge Management and our General Partner. Our General Partner and Enbridge Management are indirect subsidiaries of Enbridge, and we are a business unit of Enbridge. Our General Partner, Enbridge Management and Enbridge, through its affiliates, provide us with managerial, administrative, operational and director services pursuant to service agreements among them and us. Pursuant to these service agreements, we reimburse our General Partner, Enbridge Management and affiliates of Enbridge for the costs of these managerial, administrative, operational and director services, which costs include a portion of the compensation of the NEOs.

The boards of directors of Enbridge Management 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 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 service agreements 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, 2015 were:

- Mark A. Maki, President, Principal Executive Officer and Director
- Stephen J. Neyland, Vice President — Finance *(Principal Financial Officer)*
- D. Guy Jarvis, Executive Vice President — Liquids Pipelines and Director
- E. Chris Kaitson, Vice President — Law and Assistant Corporate Secretary
- Bradley F. Shamla, Vice President — Liquids Pipelines, Operations

Mr. Jarvis is also an executive officer of Enbridge. Mr. Jarvis serves as President, Liquid Pipelines of Enbridge. Since Mr. Jarvis is also an executive officer of Enbridge, the Human Resources and Compensation Committee of the board of directors of Enbridge, or the HRC Committee, approves the elements of compensation for him based on the recommendation of the President & Chief Executive Officer of Enbridge considering his position within Enbridge on an enterprise-wide basis.

The HRC Committee does not have responsibility for reviewing or approving compensation for employees, on an individual basis, who are not a part of Enbridge's executive leadership team. 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 HRC Committee for approval. Individual salary increases are implemented after the HRC Committee approves the overall budget. Compensation adjustments for the remaining NEOs are recommended by their supervisors and reviewed by the executive leadership team of Enbridge, including the President & Chief Executive Officer of Enbridge. 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, compensation is determined on the basis of overall performance with respect to Enbridge and all of its affiliates and not solely based on performance with respect to us.

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.

The board of directors of Enbridge implemented an Incentive Compensation Clawback Policy that enables 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 HRC Committee. As business units of Enbridge, we contribute to its overall growth, earnings and attainment of performance goals. The following table presents our historical adjusted earnings, which includes earnings from non-controlling interests and excludes the impact of non-recurring and non-operating items, as a percentage of the adjusted earnings of Enbridge for the preceding five years:

2015	2014	2013	2012	2011
19%	19%	14%	14%	17%

The elements of total compensation in 2015 for senior management of Enbridge, which includes Mr. Jarvis, 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 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, compensation comprised of performance stock units, performance stock options and incentive stock options that are tied to the share price of Enbridge common shares, MEP common units and other financial measures, and are considered 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 a competitive benefits program including health and welfare, life insurance and disability programs.
- Employment agreements — to provide specific total compensation terms in situations of involuntary termination or constructive dismissal.

The elements of compensation for NEOs other than Mr. Jarvis are similar to those described above, except they are not eligible for Enbridge performance stock options. In addition, with the exception of Messrs. Jarvis and Kaitson, no other NEOs have employment agreements. The HRC Committee makes determinations as to whether the enterprise-wide performance goals have been achieved, approves business unit results and if adjustments are necessary to more accurately reflect whether those goals have been met or exceeded. For example, the HRC Committee may determine to disregard the impacts of certain long-term financing activities on earnings when 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 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 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.

The following is a summary for 2015 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 *President, Principal Executive Officer and Director*	40%	0 – 80%	25%	50%	25%
Stephen J. Neyland *Vice President – Finance (Principal Financial Officer)*	35%	0 – 70%	25%	50%	25%
D. Guy Jarvis *Executive Vice President – Liquids Pipelines and Director*	65%	0 – 130%	25%	50%	25%
E. Chris Kaitson *Vice President – Law and Assistant Corporate Secretary*	35%	0 – 70%	25%	50%	25%
Bradley F. Shamla *Vice President – Liquids Pipelines, Operations*	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) + Business unit target incentive opportunity x (0 – 2) + Individual target incentive opportunity x (0 – 2) = Overall performance multiplier (0 – 2)	Base Salary $ x Target STIP % x Overall performance multiplier (0 – 2) = $ Short term incentive award

Enbridge Corporate Performance

Corporate performance was measured by adjusted earnings per share, or adjusted EPS, in 2015. 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 2015 EPS guidance range was $2.05 CAD to $2.35 CAD as approved by the Enbridge board of directors prior to the start of 2015. Adjustments are made to ensure the result is a fair reflection of performance. Approximately $1,903 million CAD was adjusted out of the calculation, including mark-to-market gains/losses, restructuring charges and non-cash goodwill and asset impairments. For incentive purposes, adjusted earnings also exclude the impact of certain long-term financing activities on earnings. The corporate multiplier ranges from 0 to 2.0, with 1.0 meaning that the performance measure was met. The 2015 adjusted EPS for corporate STIP performance is $2.23 CAD, resulting in a corporate multiplier of 1.20.

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. The performance measure for Messrs. Maki, Neyland and Kaitson is calculated 100% for the Gas Pipelines and Processing — Shared Services unit, resulting in a business unit multiplier of 1.28.

The performance measure for Messrs. Jarvis and Shamla is calculated at 100% for the Liquids Pipelines unit, resulting in a business unit multiplier of 1.42.

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 target performance measure was met. The business units include the Partnership, but also include portions of other Enbridge businesses.

Gas Pipelines & Processing — Shared Services					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Multiplier**	**Weighted Multiplier**
Safety, Operations & Integrity	35%	Health and Safety Training	5%	1.44	0.50
		Safety Observations	5%		
		Incident Investigation Action Items	5%		
		Total Recordable Injury Frequency	5%		
		Process Safety Incident Frequency	5%		
		Operational Risk Assessment – Inspections	5%		
		Operational Risk Reduction – Safety Audit Items	5%		
Financial	40%	EEP Liquids Adjusted Net Income	20%	1.05	0.42
		Midcoast Distributable Cash Flow	16%		
		Offshore Adjusted Net Income	4%		
Commercial	25%	Newly Secured Growth Projects	25%	1.43	0.36
Business Unit Performance multiplier					**1.28**

Liquids Pipelines					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Multiplier**	**Weighted Multiplier**
Safety and Operational Reliability	40%	Safety Observations & Training	6%	1.78	0.71
		Employee Total Recordable Injury Frequency	2%		
		Contractor Total Recordable Injury Frequency	2%		
		Incident Investigations & Inspections	10%		
		Significant Releases	10%		
		Mainline Integrity Reliability	5%		
		Facilities Integrity Reliability	5%		
Maximize Financial Performance	40%	Liquids Budgeted Earnings	40%	1.00	0.40
Superior Competitive Advantage	20%	Stakeholder Alignment	7.5%	1.54	0.31
		Risk Based Decision Making	7.5%		
		Project Implementation	5%		
Business Unit Performance Multiplier					**1.42**

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. Individual performance ratings are recommended to the HRC Committee by the President & Chief Executive Officer of Enbridge for Mr. Jarvis. The individual performance ratings for the remaining NEOs are recommended by their supervisors to the Enbridge executive leadership team, including the President & Chief Executive officer of Enbridge.

Summary of 2015 Performance Multipliers

The following table summarizes the corporate, business unit and individual performance multipliers for each NEO, 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 1.20 = 0.30	50% x 1.28 = 0.64	25% x 1.60 = 0.40	1.34
Stephen J. Neyland	25% x 1.20 = 0.30	50% x 1.28 = 0.64	25% x 1.65 = 0.41	1.35
D. Guy Jarvis	25% x 1.20 = 0.30	50% x 1.42 = 0.71	25% x 1.75 = 0.44	1.45
E. Chris Kaitson	25% x 1.20 = 0.30	50% x 1.28 = 0.64	25% x 1.65 = 0.41	1.35
Bradley F. Shamla	25% x 1.20 = 0.30	50% x 1.42 = 0.71	25% x 1.60 = 0.40	1.41

Based on the overall performance multiplier determined from the above table, short term incentive awards for the NEOs were calculated as follows:

NEO	Base Salary (a)	Target (b)	Overall Performance Multiplier (c)	Calculated STIP[1] = (a) x (b) x (c)	Actual STIP[1]
Mark A. Maki	$368,898	40%	1.34	$197,729	$197,729
Stephen J. Neyland	270,144	35%	1.35	127,643	127,881
D. Guy Jarvis[2]	430,804	65%	1.45	406,033	405,332
E. Chris Kaitson	283,184	35%	1.35	133,804	144,053
Bradley F. Shamla	275,561	35%	1.41	135,989	135,990

(1) Calculated and actual results may vary from mathematical results due to rounding and/or discretionary adjustments.

(2) The dollar amounts presented for Mr. Jarvis have been converted from Canadian dollars, or CAD, to United States dollars, or USD, using the average exchange rate for 2015 of $1.2787 CAD = $1 USD.

The calculated STIP may be adjusted for Mr. Jarvis by a recommendation of the President & Chief Executive Officer of Enbridge to the HRC Committee, which must approve any such recommendation. Any adjustment for the remaining NEO's would be reviewed by the executive leadership team of Enbridge, including the President & Chief Executive Officer of Enbridge. Enbridge's President & Chief Executive Officer approves the awards on an enterprise-wide basis.

Medium and Long-Term Incentives

Enbridge believes that a combination of 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 granted to the NEOs is contingent on meeting performance criteria and price hurdles. Specifically, when targets and performance relative to peer organizations are achieved, the value of the medium and long-term incentive is maximized for the executives while also benefitting shareholders. 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 Incentives	Amount Each Plan Contributes to Total Target Grant			
		Enbridge Performance Stock Units	MEP Performance Stock Units	Enbridge Performance Stock Options[1]	Enbridge Incentive Stock Options
Mark A. Maki	85.0%	25.5%	—	—	59.5%
Stephen J. Neyland	70.0%	12.6%	28.0%	—	29.4%
D. Guy Jarvis	225.0%	78.8%	—	67.5%	78.8%
E. Chris Kaitson	70.0%	12.6%	28.0%	—	29.4%
Bradley F. Shamla	70.0%	21.0%	—	—	49.0%

(1) Performance stock options are granted approximately once every five years to Enbridge executive officers only, and they are intended to cover a five year period. The above table displays the intended annualized value. The last regular performance stock option grant was in 2012, which was intended to provide annual value over the period from 2012 to 2016.

With the exception of Mr. Jarvis, actual award values, expressed as a percentage of base salary, range between 0% and 225% of the target medium and long-term incentive opportunity, based on individual performance history, succession potential, retention considerations and market competitiveness. Discretionary adjustments may also be considered.

Enbridge

Enbridge has three plans that make up its medium and long-term incentive program for our named executives:

- A Performance Stock Unit Plan (2007), or PSUP, which includes three-year phantom shares with performance conditions that impact payout;
- A Performance Stock Option Plan (2007), or PSOP, which includes eight-year stock options to acquire Enbridge common shares with performance and time vesting conditions; and
- An Incentive Stock Option Plan (2007), or ISOP, which includes 10-year stock options to acquire Enbridge common shares with time vesting conditions.

Only the Enbridge Executive Leadership Team, which includes Mr. Jarvis, are eligible to receive grants under the PSOP.

MEP

MEP has an additional plan that makes up its medium and long-term incentive program for senior management, for which the NEOs may be eligible:

- 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. In 2015, MEP issued performance stock units, or PSUs, under this plan.

Enbridge Plans

PSUP

The PSUP is a three-year performance-based unit plan. 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 (including additional PSUs resulting from reinvesting dividends) 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. PSUs do not involve the issuance of any shares of common stock of Enbridge. 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*.

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. Performance measures and targets are established at the start of the term to reflect levels of performance that would be considered weak, average or exceptional. Achievement of the performance targets can decrease or increase the final award value in a range of 0% to 200%. The target level at which PSUs are issued represents 100% of the number of PSUs initially granted and attainment of the established performance criteria. 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. 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: for the 2015 grant, these measures are EPS and relative price to earnings ratio, or P/E Ratio, each of which are weighted at 50%.

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 comparative 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 comparative group for the P/E Ratio for the 2015 grant.

Price/Earnings Ratio – Comparative 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.

PSOP

PSOs align the Enbridge executive leadership team, including Mr. Jarvis, with its shareholders by tying vesting to the achievement of defined performance criteria. Once the performance hurdles are met, exercisability is subject to time requirements. Enbridge grants performance stock options to its executives approximately every five years with eight year terms that become exercisable over a period of five years at a rate of 20% per year provided the performance criteria are met. The approach used to determine the common share price hurdles was determined from the Enbridge long-range plan which is integrated with the strategic growth plans of Enbridge and historic industry P/E Ratio information.

Enbridge granted performance stock options to Mr. Jarvis in 2012. The performance criteria for the 2012 performance stock options vest in equal annual installments over five years, subject to Enbridge common share price hurdles of $48.00 CAD, $53.00 CAD and $58.00 CAD on the Toronto Stock Exchange, or TSX, weighted at 40%, 40% and 20%, respectively, which must be met by February 2019. As of December 31, 2015, all of the Enbridge common share price targets have been met, therefore 60% of the grant is exercisable. For clarity, the following table further describes the vesting provisions and performance criteria of the performance stock option grant:

	% Vested				
Share price[1]	**Year 1 (20% time vested)**	**Year 2 (40% time vested)**	**Year 3 (60% time vested)**	**Year 4 (80% time vested)**	**Year 5 (100% time vested)**
Less than $48 (0% performance vested)	0%	0%	0%	0%	0%
Greater than $48 but less than $53 (40% performance vested)	8%	16%	24%	32%	40%
Greater than $53 but less than $58 (80% performance vested)	16%	32%	48%	64%	80%
Greater than $58 (100% performance vested)	20%	40%	60%	80%	100%

Attribution	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Intended annual value	20% of grant value	20% of grant value	20% of grant value	20% of grant value	20% of grant value

(1) The weighted average trading price in CAD over a period of 20 consecutive trading days. The grant price was $39.34 CAD.

ISOP

The ISOP provides regular stock options that 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 is ten years.

If an option is awarded at a time when a blackout period is in effect, the grant price and grant date of the option will be set on the sixth trading day following the termination of the blackout period, and will not be less than 100% the fair market value as of grant date (the weighted average trading price of an Enbridge common share on the TSX or NYSE for the five trading days immediately preceding grant date.) 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 2015, each of the NEOs received grants of Enbridge incentive stock options where one option is equivalent to one share of Enbridge common stock.

LTIP

In 2015, under the LTIP, MEP issued PSUs tied to MEP's publicly traded Class A common units, similar to Enbridge's PSUP. Performance measures and targets are established at the start of the term to reflect levels of performance that would be considered weak, average or exceptional. The provisions governing PSUs issued under the LTIP are consistent with those of Enbridge PSUs with the exception of the performance measures used. Achievement of the performance targets can decrease or increase the final award value in a range of 0% to 200%. PSUs issued under the LTIP do not involve the issuance of any MEP units. Throughout the term, units are added to the grants as if cash distributions were received and reinvested into additional units based on the actual cash distribution rate for MEP units. 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: for the 2015 grant, these measures are distributable cash flow per unit (DCF) growth and reduction in relative yield (Yield Ratio), each of which are weighted at 50%.

The DCF performance reflects MEP's commitment to its unitholders to achieve DCF growth that meets or exceeds average industry growth rates projected at the time of grant. DCF represents the cash MEP has available for distribution to unitholders, and is a key metric for master limited partnerships. The DCF required to achieve a two multiplier (the maximum) would demonstrate achievement of compound annual growth consistent with exceptional industry growth rate (and for the 2015 grant, anticipated asset drop-downs) and would represent exceptional performance to the investment community.

The second performance criterion is the Yield Ratio, which is a measure of how effective MEP is at deploying capital and growing cashflow and the underlying business relative to a selected comparative group of companies. A reduction in yield, relative to peers, represents improvement in both areas. The following table presents the comparative group for the Yield Ratio, for the 2015 grant.

Yield Ratio – Comparative Group of Companies	
American Midstream Partners, L.P.	QEP Midstream Partners, L.P.
Crestwood Midstream Partners, L.P.	Regency Energy Partners, L.P.
DCP Midstream Partners, L.P.	Southcross Energy Partners, L.P.
Enable Midstream Partners, L.P.	Summit Midstream Partners, L.P.
MarkWest Energy Partners, L.P.	Targa Resources Partners, L.P.

This peer group of companies was selected because they are all U.S. gas gathering and processing MLPs whose strategies involve organic growth or drop-downs from general partners, similar to MEP.

The board of directors of MEP's General Partner has the authority to approve any amendments to the performance measures, the expected levels of performance and term. Additionally, the board of directors of MEP's General Partner has the authority to waive restrictions with respect to participation in the LTIP or the maturity of grants under the LTIP for any specific participants.

Service Agreements and Allocation of Compensation to the Partnership

As discussed above, our General Partner, Enbridge Management and affiliates of Enbridge provide managerial, administrative, and operational and director services to us pursuant to service agreements and we reimburse them for the costs of such services. Through an operational services agreement among Enbridge, affiliates of Enbridge and us, we are charged for the services of executive management resident in Canada, including the services of Mr. Jarvis. Through a general and administrative services agreement among us, our General Partner, Enbridge Management and Enbridge Employee Services, Inc., a subsidiary of our General Partner, which we refer to as EES, we are charged for the services of executive management resident in the United States, including Messrs. Kaitson, Maki, Neyland and Shamla. See Item 13. *Certain Relationships and Related Transactions, and Director Independence — Other Related Party Transactions* for a discussion of these two agreements.

In connection with our annual budget process, we determine a budgeted allocation rate, which represents an estimated average percentage of expected time that will be spent by each of the NEOs on our business during the succeeding year. The NEOs provide input as to what those estimated percentages should be. Those estimates are revised each year based on historical experience and business plans for the following year. The NEOs do not keep logs of their time spent on our matters. Since the allocation rate is estimated, the actual time spent by an NEO on our behalf may vary from the budgeted allocation rate, and we may be allocated more or less of that NEO's compensation than the actual percentage of his time spent on our behalf in a given year. There were no other adjustments recognized for the years ended December 31, 2015, 2014 and 2013, for amounts reimbursed to us by Enbridge and its affiliates for the portion of the NEOs' compensation allocated to us. For 2015, the percentage of time estimated to be spent by each of the NEOs on our matters was:

- Mark A. Maki — 90%
- Stephen J. Neyland — 90%
- D. Guy Jarvis — 30%
- E. Chris Kaitson — 80%
- Bradley F. Shamla — 75%

For services provided under the operational services agreement, as part of the annual budget process, we, Enbridge and affiliates of Enbridge, which we refer to as the Canadian service providers, agree on the amount to be allocated to us, which represents an estimate of a pro-rata reimbursement of each Canadian service provider's estimated annual departmental costs, net of amounts charged to other affiliates and amounts identifiable as costs of that Canadian service provider. The Canadian service providers charge us a monthly fixed fee based on the budgeted amount.

For services provided under the general and administrative services agreement, base salary costs of EES are allocated to us based on the percentage of time spent by EES employees, including four of the NEOs, on our behalf compared with the total time of all EES employees. We are also allocated a portion of the equity-based compensation expense of EES as determined in accordance with U.S. GAAP. Pension expenses of EES, other than expenses under Enbridge's nonqualified supplemental pension plan for U.S. domiciled employees, which we refer to as the SPP, are allocated to us based on the proportion that the total headcount of EES employees assigned to us bears to the total headcount of EES. For this purpose, an employee of EES is deemed to be assigned to us if he or she works on assets we own. Pension expenses of EES attributable to the SPP are allocated to us based upon the average budgeted allocation rate. EES allocates to us that portion of its compensation expense for the STIP equal to the total salaries of employees who perform work for us multiplied by the average budgeted allocation rate divided by EES's total salary expense.

The compensation of our NEOs included in the tables below is established by Enbridge as described above. We have included in the following tables the full amount of compensation and related benefits provided for each of the NEOs, together with an estimate of the approximate time spent by each NEO on our behalf and the estimated amount of compensation cost allocated to us for the years ended December 31, 2015, 2014 and 2013, as applicable. The amount of NEO compensation allocated to us as presented below reflect the actual amount of compensation allocated to us for each particular NEO.

SUMMARY COMPENSATION TABLE

Name and Principal Position (a)	Year (b)	Salary[(1)] ($) (c)	Stock Awards[(2)] ($) (e)	Option Awards[(3)] ($) (f)	Non-Equity Incentive Plan Compensation[(4)] ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation[(5)(2)] ($) (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 President, Principal Executive Officer and Director	2015 2014 2013	366,649 361,529 370,440	129,831 592,158 429,868	397,563 392,221 338,047	197,729 164,251 220,170	(247,000) 1,326,000 (236,000)	40,227 50,872 47,392	884,999 2,887,031 1,169,917	90 90 75	796,499 2,598,328 808,311
Stephen J. Neyland Vice President – Finance (Principal Financial Officer)	2015 2014 2013	268,497 260,718 248,637	99,320 384,811 272,116	225,871 238,549 200,840	127,881 122,234 134,610	11,000 523,000 3,000	38,040 38,175 43,647	770,609 1,567,487 902,850	90 90 90	693,548 1,410,738 780,931
D. Guy Jarvis[(6)] Executive Vice President – Liquids Pipelines and Director	2015 2014 2013	426,718 463,867 —	494,158 1,311,835 —	546,466 651,694 —	405,332 421,236 —	(266,000) 902,000 —	88,473 99,144 —	1,695,147 3,849,776 —	30 30 —	508,544 1,154,933 —
E. Chris Kaitson Vice President – Law and Assistant Corporate Secretary	2015 2014 2013	281,457 — —	78,704 — —	165,342 — —	144,053 — —	19,000 — —	37,840 — —	726,396 — —	80 — —	581,117 — —
Bradley F. Shamla Vice President – Liquids Pipelines, Operations	2015 2014 2013	273,881 266,630 —	123,435 469,675 —	266,749 318,858 —	135,990 126,323 —	(380,000) 831,000 —	61,271 70,053 —	481,326 2,082,539 —	75 75 —	360,995 1,561,904 —

(1) In 2013, we classified paid time off, PTO, not taken, paid in cash in "Salaries". In 2015 and 2014, we classified this category of benefits under "Other Compensation" and have retrospectively applied this classification to 2013.

(2) The compensation expense associated with PSUs granted on January 1 in 2015, 2014 and 2013 under the PSUP for each NEO and PSUs granted on January 1, 2015 under the LTIP for Messrs. Neyland and Kaitson, that are reflected in this column represent one-third of the market value for each year the PSUs are outstanding. The PSUs are measured based on the number of respective units granted, dividends reinvested, cliff-vested, the actual or forecast performance multiplier and priced at the date of grant revalued each quarter using the spot rate on the last day of each quarter. For example, 2015 includes one-third of the market values for PSUs issued in 2015, 2014 and 2013 under the PSUP and one-third of the market values for PSUs issued in 2015 under the LTIP. In 2015, the compensation expense recorded for PSUs

granted in 2015, 2014 and 2013 include performance multipliers for the years 2015 through 2013, which are estimated 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 2* of the *Grants of Plan — Based Awards* table for additional discussion regarding the PSUs. The grant date fair value for each PSU granted under the PSUP represents the weighted average closing price of an Enbridge common share as quoted on the NYSE for the USD denominated PSUs and the Toronto Stock Exchange, or TSX, for CAD denominated PSUs for the 20 consecutive days prior to the grant date of January 1 of each year. The grant date fair value for each PSU granted under the LTIP represents the weighted average closing price of an MEP common unit as quoted on the NYSE for the 20 consecutive days prior to the grant date of January 1 of each year. Compensation expense as reported in the Summary Compensation Table above for Stock Awards has been determined using the following assumptions:

PSU Grant Date Fair Market Value Prices	2015	2014	2013
Enbridge (20-day average before January 1 of listed year) USD (NYSE)	$49.87	$41.65	$42.27
Enbridge (20-day average before January 1 of listed year) CAD (TSX)	$56.99	$44.30	$41.69
MEP (20-day average before January 1 of listed year) USD (NYSE)	$14.10	N/A	N/A

Revaluation Date	Mar-31	Jun-30	Sep-30	Dec-31
2013 – 2015 EI Grants				
Share Price/Spot Rate USD (NYSE)	$ 48.50	$ 46.79	$ 37.13	$ 33.19
Share Price/Spot Rate CAD (TSX)	$ 61.05	$ 58.41	$ 49.95	$ 46.00
Quarterly average $1CAD to USD exchange rates	$1.2412	$1.2294	$1.3079	$1.3354
2013 PSUs assumed performance multiplier	2.00	2.00	2.00	2.00
2014 PSUs assumed performance multiplier	2.00	2.00	1.89	1.89
2015 PSUs assumed performance multiplier	2.00	2.00	2.00	2.00

Revaluation Date	Mar-31	Jun-30	Sep-30	Dec-31
2015 MEP Grants				
Share Price/Spot Rate USD (NYSE)	$13.84	$10.65	$9.65	$9.72
2015 PSUs assumed performance multiplier	1.00	1.00	1.00	1.00

(3) Under the authoritative accounting provisions for share-based payments, the annual expenses for option awards that are granted under the 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. Enbridge granted PSOs to Mr. Jarvis during 2012. 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	**2015**	**2014**	**2013**
Expected option term in years (USD)	6	6	6
Expected volatility (USD)	22.36%	20.07%	19.97%
Expected dividend yield (USD)	3.20%	2.87%	2.77%
Risk-free interest rate (USD)	1.81%	1.90%	1.05%
Expected option term in years (CAD)	6	6	6
Expected volatility (CAD)	19.46%	17.07%	16.78%
Expected dividend yield (CAD)	3.20%	2.87%	2.77%
Risk-free interest rate (CAD)	0.87%	1.76%	1.34%

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 has been converted to USD using the exchange rates as set forth in the tables below.

	ISOP		
	2015	**2014**	**2013**
Exercise price in CAD (TSX)	$ 59.08	$ 48.81	$ 44.83
Grant date exchange rate for $1 USD	$1.2535	$1.1057	$1.0250
Exercise price in USD (NYSE)	$ 47.41	$ 44.09	$ 43.84
Vesting period in years	4	4	4
Option fair value on grant date in CAD	$ 6.64	$ 6.03	$ 5.45
Option fair value on grant date in USD	$ 7.10	$ 6.68	$ 6.26

(4) 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.

(5) The table which follows labeled ''All Other Compensation'' sets forth the elements comprising the amounts presented in this column.

(6) Mr. Jarvis is compensated by affiliates of Enbridge in CAD, which we have converted to USD using the weighted average exchange rates for the entire year ended December 31, 2015, 2014 and 2013 of $1.2787 CAD to $1.00 USD, $1.1045 CAD to $1.00 USD and $1.0299 CAD to $1.00 USD, respectively. The costs associated with the PSUs and options that Mr. Jarvis was granted in 2015, 2014 and 2013 were borne by Enbridge and other affiliates where they are also officers. We are allocated a portion of the remaining elements of Mr. Jarvis' compensation pursuant to the terms of the Operational Services Agreement among Enbridge, Enbridge Operational Services, Inc., or EOSI, and Enbridge Pipelines, both subsidiaries of Enbridge.

ALL OTHER COMPENSATION
(For the years ended December 31, 2015, 2014 and 2013)

Name	Year	Flexible Benefits[2] $	401(k) Matching Contributions[3] $	Other Benefits[4] $	Total
Mark A. Maki	2015	20,000	13,250	6,977	40,227
	2014	20,000	13,000	17,872	50,872
	2013	20,000	12,750	14,642	47,392
Stephen J. Neyland	2015	20,000	13,250	4,790	38,040
	2014	20,000	13,000	5,175	10,897
	2013	20,000	12,750	38,175	43,647
D. Guy Jarvis[1]	2015	50,510	—	37,963	88,473
	2014	58,138	—	41,006	99,144
	2013	—	—	—	—
E. Chris Kaitson	2015	20,000	13,250	4,590	37,840
	2014	—	—	—	—
	2013	—	—	—	—
Bradley F. Shamla	2015	20,000	13,250	28,021	61,271
	2014	20,000	13,000	37,053	70,053
	2013	—	—	—	—

(1) The amounts reported in this table for Mr. Jarvis, who is domiciled in Canada, has been converted from CAD to USD using the average exchange rate for the years ended December 31, 2015, 2014 and 2013 of $1.2787 CAD to $1.00 USD, $1.1045 CAD to $1.00 USD and $1.0299 CAD to $1.00 USD, respectively.

(2) Flexible benefits for our U.S.-domiciled NEOs represent a perquisite allowance that is paid in cash as additional compensation. Our NEOs domiciled in Canada also receive flexible benefits based on their family status and base salary. For our NEOs that are domiciled in Canada, the flexible benefits can be used to purchase additional benefits or paid in cash and they may receive up to 2.5% of base salary in matching contributions towards their flexible benefits if they make contributions into their Savings Plan to purchase Enbridge common shares.

(3) Our NEOs that are domiciled in the United States and 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 21 designated funds.

(4) Other benefits include parking, relocation, fitness, health assessments and vacation not taken and paid out in cash for our U.S. NEOs. Other benefits for our Canadian NEOs include executive medical, parking, relocation, gifts and awards and vacation not taken and paid out in cash.

Enbridge does not maintain any compensation plans for the benefit of the NEOs under which equity interests in us or Enbridge Management may be awarded. However, Enbridge allocates to us 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 units and outstanding stock options granted to certain of its officers, including the NEOs. The costs we are charged with respect to option grants represent a portion of the costs determined in accordance with U.S. GAAP.

The PSUs are granted to the NEOs pursuant to the PSUP and LTIP. 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. The PSUs and stock options granted in 2013 through 2015 to our U.S. domiciled NEOs are denominated in USD while those granted to NEOs domiciled in Canada are denominated in CAD. The three tables which follow set forth information concerning PSUs and stock options granted during the year ended December 31, 2015, outstanding at December 31, 2015 and the number of awards vested and exercised during the year ended December 31, 2015 by each of the NEOs.

GRANTS OF PLAN-BASED AWARDS

Name (a)	Plan Name (b)	Approval Date (b)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1) Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards(2) Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Option Awards: Number of Securities Underlying Options(3) (#) (j)	Exercise or Base Price of Option Awards(3) ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards(3) ($) (l)
Mark A. Maki	PSUP	18-Feb-15	1-Jan-15	—	—	—	—	3,590	7,180	—	—	179,033
	ISOP	18-Feb-15	2-Mar-15	—	—	—	—	—	—	60,870	47.41	432,177
	STIP	1-Feb-16	26-Feb-16	—	147,559	295,118	—	—	—	—	—	—
Stephen J. Neyland	PSUP	18-Feb-15	1-Jan-15	—	—	—	—	1,690	3,380	—	—	84,280
	LTIP	17-Feb-15	1-Jan-15	—	—	—	—	10,210	20,420	—	—	143,961
	ISOP	18-Feb-15	2-Mar-15	—	—	—	—	—	—	24,630	47.41	174,873
	STIP	1-Feb-16	26-Feb-16	—	94,550	189,101	—	—	—	—	—	—
D. Guy Jarvis	PSUP	18-Feb-15	1-Jan-15	—	—	—	—	8,370	16,740	—	—	413,309
	ISOP	18-Feb-15	2-Mar-15	—	—	—	—	—	—	68,050	47.14	360,488
	STIP	1-Feb-16	26-Feb-16	—	280,022	560,045	—	—	—	—	—	—
E. Chris Kaitson	PSUP	18-Feb-15	1-Jan-15	—	—	—	—	1,390	2,780	—	—	69,319
	LTIP	17-Feb-15	1-Jan-15	—	—	—	—	7,850	15,700	—	—	110,685
	ISOP	18-Feb-15	2-Mar-15	—	—	—	—	—	—	19,530	47.41	138,663
	STIP	1-Feb-16	26-Feb-16	—	99,114	198,229	—	—	—	—	—	—
Bradley F. Shamla	PSUP	18-Feb-15	1-Jan-15	—	—	—	—	2,550	5,100	—	—	127,169
	ISOP	18-Feb-15	2-Mar-15	—	—	—	—	—	—	43,210	47.41	306,791
	STIP	1-Feb-16	26-Feb-16	—	96,446	192,893	—	—	—	—	—	—

(1) The estimated future payouts under non-equity incentive award plans represents awards under the Enbridge STIP as presented above in the Compensation Discussion and Analysis under the section labeled Short-Term Incentive Plan.

(2) The grant date fair value for each PSU granted to each of our U.S.-based NEOs in 2015 was $49.87 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, 2015. The grant date fair value for each PSU granted under the PSUP to each of our Canadian based NEOs was $56.99 CAD, representing the volume weighted average closing price of one Enbridge common share as quoted on the TSX for the 20 days immediately preceding the start of the performance period that began on January 1, 2015. We have converted the grant date fair value for the Canadian PSU grants made from CAD to USD using an average exchange rate of $1.1542 CAD to $1.00 USD, representing an average for the 20 trading days immediately preceding the start of the performance period that began on January 1, 2015. The grant date fair value for each PSU granted under the LTIP in 2015 was $14.10 USD, representing the volume weighted average closing price of one MEP common unit as quoted on the NYSE for the 20 trading days immediately preceding the start of the performance period that began on January 1, 2015.

(3) The exercise price of the incentive stock options at the time of grant was $59.08 CAD for Canadian-domiciled NEOs and $47.41 USD for NEOs domiciled in the United States.

The amounts included as the grant date fair value for the 2015 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:

USD Option Value	CAD Option Value
6 years expected term;	6 years expected term;
22.36% expected volatility;	19.46% expected volatility;
3.20% expected dividend yield; and	3.20% expected dividend yield; and
1.81% risk free interest rate.	0.87% risk free interest rate.

The fair value of options granted as computed using these assumptions is $7.10 USD or $6.64 CAD. The $6.64 CAD option value and the $59.08 CAD exercise price have been converted to USD using an exchange rate of $1.2535 CAD = $1 USD representing the noon buying rate at the Bank of Canada for transfers of CAD on the grant date of March 2, 2015. The grant date fair value is expensed over the shorter of the vesting period for the options, generally 4 years, and in the year granted for employees age 55 and over and eligible for early retirement.

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] ($) (e)	Option Expiration Date[1] (f)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[4] (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)	Unit Maturity Date
Mark A. Maki	—	60,870	47.41	2-Mar-25	3,717	123,368	31-Dec-17
	15,763	47,287	44.09	13-Mar-24	5,373	178,325	31-Dec-16
	31,800	31,800	43.84	27-Feb-23			
	46,238	15,412	38.65	2-Mar-22			
	76,400	—	28.99	14-Feb-21			
Stephen J. Neyland	—	24,630	47.41	2-Mar-25	1,750	58,076	31-Dec-17
	9,075	27,225	44.09	13-Mar-24	11,412[5]	110,922	31-Dec-17
	20,525	20,525	43.84	27-Feb-23	2,660	88,280	31-Dec-16
	29,325	9,775	38.65	2-Mar-22			
	33,450	—	28.99	14-Feb-21			
	7,700	—	21.97	16-Feb-20			
	2,750	—	15.80	25-Feb-19			
D. Guy Jarvis	—	68,050	47.13	2-Mar-25	8,663	551,578	31-Dec-17
	19,588	58,762	44.14	13-Mar-24	11,752	748,239	31-Dec-16
	30,175	30,175	43.74	27-Feb-23			
	22,900	22,900	38.77	2-Mar-22			
	25,300	—	29.11	14-Feb-21			
	101,640	67,760	39.77	15-Aug-20			
E. Chris Kaitson	—	19,530	47.41	2-Mar-25	1,439	47,766	31-Dec-17
	5,813	17,437	44.09	13-Mar-24	8,774[5]	85,283	31-Dec-17
	14,775	14,775	43.84	27-Feb-23	2,075	68,858	31-Dec-16
	21,525	7,175	38.65	2-Mar-22			
	35,800	—	28.99	14-Feb-21			
	13,200	—	21.97	16-Feb-20			
	27,000	—	15.80	25-Feb-19			
	27,000	—	20.17	19-Feb-18			
	11,400	—	16.30	9-Feb-17			
	13,600	—	15.79	13-Feb-16			
Bradley F. Shamla	—	43,210	47.41	2-Mar-25	2,640	87,629	31-Dec-17
	8,875	26,625	44.09	13-Mar-24	3,139	104,170	31-Dec-16
	26,000	26,000	43.74	27-Feb-23			
	37,763	12,587	38.77	2-Mar-22			
	65,400	—	29.11	14-Feb-21			
	25,400	—	22.34	16-Feb-20			
	30,000	—	15.78	25-Feb-19			
	23,000	—	19.90	19-Feb-18			
	11,800	—	16.30	9-Feb-17			

(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 would become fully vested on February 14, 2015 representing four years following the grant date.

(2) PSOs were provided to Mr. Jarvis on August 15, 2012 and are similar to the incentive stock options, except that the quantities that become exercisable are subject to both time and performance requirements. PSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge common share for each option held when the specified time and performance conditions are met. Upon the performance hurdles being met, the PSOs are also time vested 20% annually over five years. As of December 31, 2015, all three of the Enbridge common share price targets for the 2012 grant have been met, therefore 60% of the grant is exercisable.

(3) The exercise prices of the ISOs issued during 2007 and prior years are denominated in CAD and have been adjusted for the noon exchange rate on the date of grant. 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. Beginning in 2008, ISOs granted to NEOs domiciled in the United States are denominated in USD while those NEOs domiciled in Canada are denominated in CAD. PSOs are granted in CAD to NEOs domiciled in either Canada or the United States. The ISOs and PSOs denominated in CAD have been converted to USD using the exchange rate on the grant dates as set forth below:

Grant Date	Option Exercise Price CAD (TSX)	Exchange Rate $1 CAD/USD	Option Exercise Price USD (converted)
February 13, 2006	18.2350	0.8660	15.7915
February 9, 2007	19.1300	0.8519	16.2968
August 15, 2007	18.2850	0.9306	17.0160
February 19, 2008	20.2100	0.9843	19.8927
February 25, 2009	19.8050	0.7964	15.7727
February 16, 2010	23.2950	0.9591	22.3422
February 14, 2011	28.7750	1.0116	29.1088

Grant Date	Option Exercise Price CAD (TSX)	Exchange Rate $1 CAD/USD	Option Exercise Price USD (converted)
March 5, 2012	38.3400	1.0113	38.7732
August 15, 2012	39.3400	1.0110	39.7727
February 27, 2013	44.8300	0.9756	43.7361
March 13, 2014	48.8100	0.9044	44.1438
March 2, 2015	59.0800	0.7978	47.1340

(4) 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 *Medium and Long-Term Incentives*, at the end of the term. The amounts represented in the column are the number of units that have not vested at the common share price of one Enbridge common share on the NYSE at December 31, 2015 equating to $33.19 per share or on the TSX of $46.00 per common share converted to USD as $33.24 per share at the conversion rate of $1.3840 CAD to $1.00 USD or one MEP unit on the NYSE at December 31, 2015 equating to $9.72. The market or payout values presented assume a performance multiplier of 1.0 for PSUs granted under the PSUP in 2015 and 2014 and PSUs granted under the LTIP in 2015, which represents the target level.

(5) These amounts represent stock awards granted under the LTIP.

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	—	—	4,270	273,017
Stephen J. Neyland	—	—	2,518	161,010
D. Guy Jarvis	—	—	8,150	523,340
E. Chris Kaitson	23,200	636,116	1,971	126,008
Bradley F. Shamla	13,400	343,508	3,063	196,691

(1) The number of common shares acquired on vesting for stock awards represents the number of PSUs issued in 2013 and the related dividends paid that were used to acquire additional PSUs, all of which matured on December 31, 2015. As discussed in *Medium and Long-Term Incentives*, 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 2013 is expected to occur on or about March 11, 2016.

(2) The value realized on vesting is determined based on the 20-day volume weighted-average value of an Enbridge common share of $31.97 USD for the NEOs domiciled in the U.S. or $43.97 CAD for the NEOs domiciled in Canada. In each case the common share price is multiplied by an estimated 2.00 performance factor multiplied by the number of PSUs, and is then converted to USD, as applicable, using an average exchange rate of $1.3705 CAD to $1.00 USD for the 20 trading days prior to the maturity date of December 31, 2015.

Pension Plan

Enbridge sponsors two qualified pension plans, the Retirement Plan for the Employees of Enbridge Inc. and its Canadian 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. 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 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 equal to: (a) 1.6% of the average of the participant's highest average annual salary multiplied by (b) the number of credited years of service. Other provisions are aligned with the senior management provisions described below. For employees hired after January 1, 2002, the Pension Plans provide cash balance benefits with pay credits ranging from 4% – 10% depending on the employees' pensionable pay, age and years of service.

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, 2015 assuming the eligibility requirements for an unreduced pension have been satisfied. We have converted pensions payable in CAD into USD at the rate of $1.384 CAD to $1.00 USD, the exchange rate for the year ended December 31, 2015. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	4.10% at year end 2015
Salary increases	None
Inflation	2.25% per year
Retirement age	Age when first eligible for an unreduced pension[(1)]
Terminations	None
Mortality Rates:	
Pre-retirement	None
Post-retirement	Society of Actuaries RP2014 annuity/non-annuitant table without collar adjustment with full generational mortality improvement under Scale MP 2015

(1) This is age 60 for all executives except for Messrs. Maki and Shamla, who are eligible for an unreduced pension at age 55 and Mr. Neyland who is eligible at age 57.

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	74,000
	EI SPP	1.92	168,000
	US QPP	27.40	1,972,000
	US SPP	27.40	1,809,000
Stephen J. Neyland	US QPP	13.50	232,000
	US SPP	11.00	868,000
D. Guy Jarvis	EI RPP	15.50	464,000
	EI SPP	15.50	1,649,000
E. Chris Kaitson	US QPP	14.58	1,029,000
	US SPP	14.58	851,000
Bradley F. Shamla	EI RPP	14.44	477,000
	EI SPP	14.44	724,000
	US QPP	10.44	646,000
	US SPP	2.64	t125,000

(1) For all NEOs with the exception of Messrs. Maki and Shamla, combined US SPP and EI SPP service represents years of service as a senior management employee. Mr. Maki has 16.00 years and Mr. Shamla has 14.67 years as a senior management employee.

Employment Agreements

In 2014, Enbridge entered into an executive employment agreement with Mr. Jarvis and in 2001, Enbridge entered into an executive employment agreement with Mr. Kaitson. The terms of the agreements continue until the earlier of their voluntary retirement in accordance with Enbridge's retirement policies for its senior employees, voluntary resignation, death or termination of employment by Enbridge. The agreements provide that Enbridge will pay severance benefits to Messrs. Jarvis and Kaitson as set forth in the table below, if their employment is terminated. The remaining NEOs do not have an employment agreement with us or any other Enbridge affiliate. Since 2007, it has been Enbridge's policy not to enter into employment agreements granting "single trigger" voluntary termination rights in favor of the executive.

The following table provides a summary of the incremental compensation that Enbridge would pay to Messrs. Jarvis and Kaitson under the terms of their employment agreements upon the occurrence of one of the foregoing events:

Type of Termination	Base Pay	Short-term Incentive	Long-term Incentive	Benefits	Pension
Resignation *(Voluntary)*	None	Payable in full if executive has worked the entire calendar year[(1)]. Otherwise none.	Performance stock units are forfeited. Vested options must be exercised within 30 days of resignation or by the end of the original term, whichever is sooner. Unvested stock options are cancelled.	None	Credited service no longer earned.
Retirement *(Voluntary)*	None	Current year's incentive is pro-rated based on retirement date.	Performance stock units are prorated to retirement date and the value and performance is assessed and paid at the end of the term. Non-qualified stock options continue to vest and vested options are exercisable for three years after the retirement date or until the end of the original term (whichever is sooner). Qualified stock options have immediate vesting (for that which would have vested in the three years following retirement) and vested options can be exercised for three months after the retirement date or until the end of the original term (whichever is sooner). Performance stock options are prorated for the period of active employment in the 5 year period starting January 1 of the year of grant. They are exercisable until the later of three years after retirement or 30 days after the date by which the share price targets must be met (or up to the date the option expires, whichever is earlier), as long as the share price targets are met.	Post retirement benefits begin.	Credited service no longer earned.
Constructive Dismissal *(Involuntary)* Not for Cause *(Involuntary)*	Base salary is paid out in a lump sum representing two years.	The average of short-term incentive awards received in the past two years multiplied by two times[(2)]; plus the current year's short-term incentive, prorated based on service before employment was terminated.	Performance stock units are prorated to date of termination (or notice period) and the value and performance is assessed and paid at the end of the term. Vested stock options are exercisable in accordance with their terms.[(3)] Unvested stock options are paid in cash.	Benefits of two years' value is paid out in a lump sum.[(4)]	Two additional years of pension accrual are added to the final pension calculation.
Change of Control			Performance stock units mature and value is assessed and paid based on performance measures achieved to date. All stock options vest.		

(1) Mr. Kaitson has to be employed on the day of payout to receive his short-term incentive.

(2) Mr. Kaitson's short-term incentive payout uses gross amount of last bonus paid multiplied by two times.

(3) Where applicable, both time and performance vesting conditions must have been met in order to be considered exercisable.

(4) Mr. Kaitson's benefits would continue for a period of two year's rather than be paid in a lump sum.

Performance stock options have the same termination provisions as incentive stock options except:

- For retirement, Enbridge prorates performance stock options for the period of active employment in the 5 year period starting January 1 of the year of grant. The executive officer can exercise these options until the later of three years after retirement or 30 days after the share price targets must be met (or up to the date the option expires, whichever is earlier), as long as the performance criteria are met;
- For death, unvested options are pro-rated and the plan assumes performance requirements have been met;
- For involuntary termination (not for cause), unvested options are pro-rated; and
- For change of control, the plan assumes the performance requirements have been met.

In addition, Mr. Jarvis will receive:

- Up to a maximum of $20,000 for financial or career counseling assistance.
- An amount in cash equal to the value of all of such executive officer's accrued and unpaid vacation pay.
- Annual flexible perquisite, flex credit allowance and savings plan matching contributions over the severance period (2 years).

In addition, Mr. Kaitson will receive:

- Savings plan matching contributions over the severance period (2 years).

After his departure, Mr. Jarvis is subject to restrictions on (1) any practice or business in competition with Enbridge or its affiliates for one year (2) disclosure of the confidential information of Enbridge or its affiliates for two years and (3) recruitment for two years. Mr. Kaitson is subject to restrictions on (1) disclosure of the confidential information of Enbridge or its affiliates indefinitely.

In the event of a termination that would result in severance benefits, Enbridge would owe incremental benefits to Mr. Jarvis with a value of approximately $4 million and Mr. Kaitson with a value of approximately $1 million. Such amounts assume that termination was effective as of December 31, 2015, and as a result include amounts earned through such time and are estimates of the amounts which would be paid out to Messrs. Jarvis and Kaitson upon termination under such circumstances. The actual amounts to be paid out can only be determined at the time of such executives' separation from Enbridge.

Director Compensation

As a partnership, we are managed by Enbridge Management, as the delegate of our General Partner. The boards of directors of Enbridge Management and our General Partner are comprised of the same persons. 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 or Enbridge Management do not receive any additional compensation for serving in those capacities.

As of July 1, 2015, under the Director Compensation Plan, non-employee directors receive an annual retainer of $165,000, with no additional fees for attending regular meetings. The annual retainer paid to the Chairman of the Board is $20,000 and the annual retainer paid to the Chairman of the Audit Committee is $15,000. The out-of-state travel fee is $1,500 per meeting. In addition, the Director Compensation Plan has set the retainer paid to a Director serving as Chairman of any Special Committee that may be constituted from time to time to $10,000 for each committee. Each member of a Special Committee receives $1,500 per meeting.

The Corporate Governance Guidelines provide an expectation that independent directors will hold a personal investment in us or Enbridge Management or both, of at least two times the annual board retainer, which, based on the current annual retainer would equal $330,000 (i.e., 2 X $165,000 = $330,000). Directors would be expected to achieve the foregoing level of equity ownership 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 ($) (b)
Jeffrey A. Connelly *Chairman of the Board*	232,000
J. Herbert England *Audit Committee Chairman*	175,250
Dan A. Westbrook	186,500
Rebecca B. Roberts[(1)]	39,250
J. Richard Bird, D. Guy Jarvis, Mark A. Maki, C. Gregory Harper and John K. Whelen[(2)]	—

(1) Through March 19, 2015, when Mrs. Roberts resigned as a director.

(2) Messrs. Jarvis, Maki, Harper and Whelen are also employees of Enbridge or its subsidiaries and thus do not receive any compensation as a director in addition to their standard compensation as an employee of Enbridge or its subsidiaries. Until his retirement as an employee of Enbridge on March 31, 2015, Mr. Bird did not receive any compensation as a director in addition to his standard compensation as an employee of Enbridge. After his retirement, pursuant to a consulting arrangement with Enbridge, Mr. Bird continued to serve as a director on behalf of Enbridge. Mr. Bird waived the director compensation from Enbridge Management and our General Partner for which he was otherwise eligible in 2015.

Each director is indemnified for actions associated with being a director to the fullest extent permitted under Delaware law, and we maintain errors and omissions insurance.

COMPENSATION REPORT OF THE BOARD OF DIRECTORS

The Board of Directors of Enbridge Energy Management, L.L.C., as delegate of the General Partner of Enbridge Energy Partners, L.P., 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

Mark A. Maki
President, Principal Executive Officer and Director

/s/ C. Gregory Harper

C. Gregory Harper
Executive Vice President — Gas Pipelines & Processing and Director

/s/ D. Guy Jarvis

D. Guy Jarvis
Executive Vice President — Liquids Pipelines and Director

/s/ J. Richard Bird

J. Richard Bird
Director

/s/ Jeffrey A. Connelly

Jeffrey A. Connelly
Director

/s/ John K. Whelen

John K. Whelen
Director

/s/ J. Herbert England

J. Herbert England
Director

/s/ Dan A. Westbrook

Dan A. Westbrook
Director

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information as of February 17, 2016 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 Management, L.L.C. 1100 Louisiana St., Suite 3300 Houston, TX 77002	i-units	75,911,421	100.0
Enbridge Energy Company, Inc. 1100 Louisiana St., Suite 3300 Houston, TX 77002	Class A common units	46,518,336	17.7
	Class B common units	7,825,500	100.0
	Series 1 Preferred Units	48,000,000	100.0
	Class D units	66,100,000	100.0
	Class E units	18,114,975	100.0
	Incentive distribution units	1,000	100.0
Deutsche Bank AG[(1)] Taunusanlage 12 60325 Frankfurt am Main Federal Republic of Germany	Class A common units	15,079,296	5.75
ALPS Advisors, Inc.[(1)] 1290 Broadway, Suite 1100 Denver, CO 80203	Class A common units	14,700,532	5.61
Alerian MLP ETF[(1)] 1290 Broadway, Suite 1100 Denver, CO 80203	Class A common units	14,635,751	5.58

(1) Reflects the securities beneficially owned by the Asset and Wealth Management business group of Deutsche Bank AG and its subsidiaries and affiliates.

We do not have any shares that have been approved for issuance under an equity compensation plan.

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 17, 2016 with respect to each class of our units and the listed shares of Enbridge Management beneficially owned by the NEOs and directors of the General Partner and Enbridge Management and all executive officers and directors of the General Partner and Enbridge Management as a group:

	Enbridge Energy Management, L.L.C.			Enbridge Energy Partners, L.P.		
Name	**Title of Class**	**Number of Shares[1]**	**Percent of Class**	**Title of Class**	**Amount and Nature of Beneficial Ownership[1]**	**Percent of Class**
Jeffrey A. Connelly[2]	Listed Shares	—	*	Class A common units	20,000	*
J. Richard Bird[3]	Listed Shares	104,536	*	Class A common units	—	*
J. Herbert England	Listed Shares	—	*	Class A common units	8,626	*
C. Gregory Harper	Listed Shares	—	*	Class A common units	—	*
D. Guy Jarvis	Listed Shares	—	*	Class A common units	—	*
Mark A. Maki	Listed Shares	6,466	*	Class A common units	4,000	*
Dan A. Westbrook[4]	Listed Shares	—	*	Class A common units	23,000	*
John K. Whelen	Listed Shares	—	*	Class A common units	—	*
E. Chris Kaitson	Listed Shares	—	*	Class A common units	—	*
Stephen J. Neyland[5][6]	Listed Shares	9,537	*	Class A common units	1,200	*
Bradley F. Shamla	Listed Shares	—	*	Class A common units	—	*
All executive officers, directors and nominees as a group (17 persons)	Listed Shares	120,539	*	Class A common units	56,826	*

* 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 or Listed Shares attributed to him or her.

(2) The 20,000 Class A common units deemed beneficially owned by Mr. Connelly, 20,000 Class A common units are held in the Susan K. Connelly Family Trust, of which Mr. Connelly is the trustee and a beneficiary.

(3) The 104,536 Listed Shares owned by Mr. Bird are held by an investment holding corporation over which he exercises full control and direction.

(4) Of the 23,000 Class A common units deemed beneficially owned by Mr. Westbrook, 16,000 Class A common units are held by The Westbrook Trust, for which Mr. Westbrook is the trustee and beneficiary, and 7,000 Class A common units are held by the Mary Ruth Westbrook Trust, for which Mr. Westbrook is the sole trustee and beneficiary.

(5) The 9,537 Listed shares beneficially owned by Mr. Neyland are held in a Family Trust for which Mr. Neyland is a co-trustee as well as a beneficiary.

(6) The 1,200 Class A common units beneficially owned by Mr. Neyland are held in a Family Trust for which Mr. Neyland is a co-trustee as well as a beneficiary.

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

Certain Relationships and Related Transactions

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties. For further discussion of these and other related party transactions, refer to Part II, Item 8. *Financial Statements and Supplementary Data*, under Note 12. *Related Party Transactions*.

Interest of the General Partner in the Partnership

At December 31, 2015, our General Partner had the following ownership interests in us:

	Quantity	Effective Ownership %
Series 1 preferred units	48,000,000	9.9%
Class D units	66,100,000	13.6%
Class E units	18,114,975	3.7%
Class A common units	46,518,336	9.6%
Class B common units	7,825,500	1.6%
IDUs	1,000	0.0%
General Partner interest	—	2.0%
Enbridge Management shares (Listed and Voting)	8,564,645	1.8%
Total	195,124,456	42.2%

Interest of Enbridge Management in the Partnership

At December 31, 2015, Enbridge Management owned 73,285,739 i-units, representing a 15.1% limited partner interest in us. The i-units are a special class of our limited partner interests. All of our i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management's limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the partnership agreement and the provisions of Enbridge Management's limited liability company agreement, the number of outstanding Enbridge Management shares and the number of our i-units will at all times be equal.

Cash Distributions

As discussed in Part II, Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*, we make quarterly cash distributions of our available cash to our General Partner and limited partners. The holders of our i-units received in-kind distributions under the partnership agreement. Our General Partner, through its ownership in our incentive distribution units, or IDUs, receives incremental incentive cash distributions on the portion of cash distributions that exceed certain target thresholds on a per unit basis as follows:

	Unitholders	General Partner and IDUs
Quarterly Cash Distributions per Unit:		
Up to $0.5435 per unit	98%	2%
Target greater than $0.5435 per unit	75%	25%

During 2015, we paid cash and incentive distributions to our General Partner for its general partner ownership interest of approximately $16.8 million and cash distributions of $152.4 million, $31.5 million, $107.3 million, $18.1 million, and $17.0 million in connection with its ownership of the Class D units, Class E units, Class A common units, Class B common units, and IDUs, respectively. The cash distributions we make to our General Partner for its general partner ownership interest exclude an amount equal to 2% of the i-unit distributions to maintain its 2% general partner interest.

In-Kind Distributions

Enbridge Management, as owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our Class A and Class B common units, we issue additional i-units to Enbridge Management in an amount determined by dividing the cash amount distributed per limited partner unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. In 2015, 2014 and 2013, we distributed a total of 4,980,552, 4,562,088 and 3,769,989 i-units to Enbridge Management, on a split-adjusted basis, and retained cash totaling approximately $161.2 million, $143.9 million and $113.8 million in connection with these in-kind distributions.

General Partner Contributions

Pursuant to our partnership agreement, our General Partner is at all times required to maintain its 2% general partner ownership interest in us. During 2015 and 2013, in connection with our various issuances and sales of Class A common units, our General Partner contributed approximately $6.0 million and $10.8 million, respectively, to us to maintain its 2% general partner ownership interest. The General Partner did not contribute during 2014.

Other Related Party Transactions

We do not directly employ any of the individuals responsible for managing or operating our business, nor do we have any directors. We obtain managerial, administrative and operational services from our General Partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, Enbridge Management and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our General Partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

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 or Enbridge Management, 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 Enbridge Management and 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.

The Enbridge Statement of Business Conduct sets forth policies and procedures for the review and approval of certain transactions with persons affiliated with us.

During 2015, 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 Jordan Connelly, the son of Jeffrey A. Connelly, a member of the Board of Directors. Mr. Connelly is employed in our Houston office as a Gas Supply Representative. During 2015, he received total cash compensation of $94,705.57 and benefits estimated at approximately 34% of his base compensation for a total of $123,684.42.

Director Independence

For a discussion of director independence, see Item 10. *Directors, Executive Officers and Corporate Governance.*

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,	
	2015	2014
	(in millions)	
Audit fees[(1)]	$2.8	$2.8
Tax fees[(2)]	0.8	0.9
Total	$3.6	$3.7

(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 Committee of Enbridge Management's board of directors; however, services up to $50,000 may be approved by the Chairman of the Audit Committee, under the board of directors' delegated authority. All services in 2015 and 2014 were approved by the Audit 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* 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, 2015, 2014 and 2013.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2015, 2014 and 2013.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013.

e. Consolidated Statements of Financial Position as of December 31, 2015 and 2014.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2015, 2014 and 2013.

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, 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.

Enbridge Energy Partners, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.,
as delegate of the General Partner

Date: February 17, 2016

By: /s/ Mark A. Maki
Mark A. Maki
President and
Principal Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 17, 2016 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ Mark A. Maki
Mark A. Maki
President, Principal Executive Officer and Director

/s/ C. Gregory Harper
C. Gregory Harper
Executive Vice President — Gas Pipelines & Processing and Director

/s/ D. Guy Jarvis
D. Guy Jarvis
Executive Vice President — Liquids Pipelines 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. Richard Bird
J. Richard Bird
Director

/s/ John K. Whelen
John K. Whelen
Director

/s/ Jeffrey A. Connelly
Jeffrey A. Connelly
Director

/s/ J. Herbert England
J. Herbert England
Director

/s/ Dan A. Westbrook
Dan A. Westbrook
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 the Partnership (incorporated by reference to Exhibit 3.1 of our Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 of our Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
3.3	Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P., dated as of January 2, 2015 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K, filed on January 8, 2015).
3.4	Amendment No. 1 to Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed on July 30, 2015).
3.5	Irrevocable Waiver dated as of June 18, 2014, made by Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 19, 2014).
4.1	Form of Certificate representing Class A common units (incorporated by reference to Exhibit 4.1 of our Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
4.2	Series 1 Preferred Unit Purchase Agreement, dated May 7, 2013 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on May 13, 2013).
4.3	Thirteenth Supplemental Indenture dated as of October 6, 2015 between Enbridge Energy Partners, L.P. and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K, filed on October 6, 2015).
4.4	Fourteenth Supplemental Indenture dated as of October 6, 2015 between Enbridge Energy Partners, L.P. and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K, filed on October 6, 2015).
4.5	Fifteenth Supplemental Indenture dated as of October 6, 2015 between Enbridge Energy Partners, L.P. and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K, filed on October 6, 2015).
10.1	Intercorporate Services Agreement, dated as of November 13, 2013, by and between Midcoast Energy Partners, L.P. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on November 19, 2013).
10.2	Financial Support Agreement, dated as of November 13, 2013, by and between Midcoast Operating, L.P. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on November 19, 2013).
10.3	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership (incorporated by reference to Exhibit 10.1 of our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 19, 2009).
10.4	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership (incorporated by reference to Exhibit 10.2 of our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 19, 2009).
10.5	Contribution Agreement (incorporated by reference to Exhibit 10.1 of our Registration Statement on Form S-3/A, filed on July 8, 2002).

Exhibit Number	Description
10.6	First Amendment to Contribution Agreement (incorporated by reference to Exhibit 10.8 of our Registration Statement on Form S-1/A, filed on September 24, 2002).
10.7	Second Amendment to Contribution Agreement (incorporated by reference to Exhibit 99.3 of our Current Report on Form 8-K, filed on October 31, 2002).
10.8	Contribution Agreement, dated as of December 23, 2014, by and among, Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on December 30, 2014).
10.9	Contribution Agreement among Enbridge Energy Company, Inc., Enbridge Pipelines (Mainline Expansion) L.L.C., the OLP, the Partnership, and Enbridge Pipelines (Lakehead) L.L.C. dated December 6, 2012 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on December 6, 2012).
10.10	Contribution, Conveyance and Assumption Agreement, dated as of November 13, 2013, by and among Enbridge Energy Partners, L.P., Midcoast Energy Partners, L.P., Midcoast Holdings, L.L.C., Midcoast Operating, L.P. and Midcoast OLP GP, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on November 19, 2013).
10.11	Sixth Amended and Restated Agreement of Limited Partnership of Enbridge Energy, Limited Partners, dated January 2, 2015, by and among and Enbridge Energy Partners, L.P., Enbridge Pipelines (Lakehead) L.L.C., Enbridge Pipelines (Wisconsin) Inc., Enbridge Energy Company, Inc., Enbridge Pipelines (Eastern Access) L.L.C. and Enbridge Pipelines (Mainline Expansion) L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on January 8, 2015).
10.12	Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy, Limited Partners, dated July 30, 2015, by and among and Enbridge Energy Partners, L.P., Enbridge Pipelines (Lakehead) L.L.C., Enbridge Pipelines (Wisconsin) Inc., Enbridge Energy Company, Inc., Enbridge Pipelines (Eastern Access) L.L.C. and Enbridge Pipelines (Mainline Expansion) L.L.C. (incorporated by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q, filed on July 30, 2015).
10.13	Delegation of Control Agreement (incorporated by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q filed on November 14, 2002).
10.14	First Amending Agreement to the Delegation of Control Agreement, dated February 21, 2005 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q, filed on May 5, 2005).
10.15	Amended and Restated Treasury Services Agreement (incorporated by reference to Exhibit 10.3 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.16	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.17	General and Administrative Services Agreement (incorporated by reference to Exhibit 10.5 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.18	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.19	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 Current Report on Form 8-K, filed on November 19, 2013).
10.20	Commercial Paper Dealer Agreement between the Partnership, as Issuer, and Banc of America Securities LLC, as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on May 3, 2005).
10.21	Commercial Paper Dealer Agreement between the Partnership, as Issuer, and Deutsche Bank Securities Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on May 3, 2005).

Exhibit Number	Description
10.22	Commercial Paper Dealer Agreement between the Partnership, as Issuer, and Goldman, Sachs & Co., as Dealer, dated April 21, 2005 (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed on May 3, 2005).
10.23	Commercial Paper Dealer Agreement between the Partnership, as Issuer, Merrill Lynch, Pierce, Fenner, and Smith Incorporated and Merrill Lynch Money Markets Inc., as Dealer, dated April 21, 2005 (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on May 3, 2005).
10.24	Commercial Paper Dealer Agreement dated as of March 20, 2015, between Enbridge Energy Partners, L.P., as Issuer, and Wells Fargo Securities, LLC, as Dealer (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on March 23, 2015).
10.25	Commercial Paper Issuing and Paying Agent Agreement between the Partnership and Deutsche Bank Trust Company Americas, dated April 21, 2005 (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on May 3, 2005).
10.26	Commercial Paper Issuing and Paying Agent Agreement between the Partnership and Citigroup Global Markets Inc., dated December 15, 2010 (incorporated by reference to Exhibit 10.20 of our Annual Report on Form 10-K for the year ended December 31, 2010, filed on February 18, 2011).
10.27	Commercial Paper Dealer Program [4(2) Program] dated as of December 15, 2010 between the Partnership, as Issuer, and Citigroup Global Markets Inc., as Dealer (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K, filed on February 18, 2011).
10.28	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (incorporated by reference to Exhibit 10.19 of our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 19, 2009).
10.29	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy (incorporated by reference to Exhibit 10.17 of our 1996 Annual Report on Form 10-K for the year ended December 31, 1996, filed on February 28, 1997).
10.30	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program Phase II and Terrace Expansion Project (incorporated by reference to Exhibit 10.21 of our Annual Report on Form 10-K for the year ended December 31, 1998, filed on March 22, 1999).
10.31	Offer of Settlement, dated December 21, 2005, as filed with the Federal Energy Regulatory Commission for approval to implement an additional component of the Facilities Surcharge to permit recovery by Enbridge Energy, Limited Partnership of the costs for the Southern Access Mainline Expansion and approval of the Offer of Settlement dated March 16, 2006 (incorporated by reference to Exhibit 10.3 of our Quarterly Report on Form 10-Q, filed on July 31, 2007).
+10.32	Executive Employment Agreement between Enbridge Inc. and D. Guy Jarvis entered into on March 14, 2014 (incorporated by reference to Exhibit 10.1 to our Amended Current Report on Form 8-K/A, filed on March 18, 2014).
+10.33	Executive Employment Agreement, entered into February 11, 2014, between C. Gregory Harper, the Executive, and Enbridge Employee Services, Inc., effective January 30, 2014 (incorporated by reference to Exhibit 10.31 of our Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 18, 2014).
+10.34	Executive Employment Agreement, dated December 20, 2012, between Leon Zupan, the Executive, and Enbridge Inc., the company effective August 1, 2012. (incorporated by reference to Exhibit 10.1 on Form 10-K for the year ended December 31, 2012, filed on February 15, 2013).
+10.35	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.27 of our Annual Report on Form 10-K, filed on March 28, 2003).
+10.36	Enbridge Incentive Stock Option Plan (2002), dated May 3, 2002 (incorporated by reference to Exhibit 10.2 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).

Exhibit Number	Description
+10.37	Enbridge Incentive Stock Option Plan (2007) dated January 1, 2007 (incorporated by reference to Exhibit 10.3 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).
+10.38	Enbridge Performance Stock Option Plan (2007) dated January 1, 2007 (incorporated by reference to Exhibit 10.4 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).
+10.39	Enbridge Performance Stock Option Plan (2007), amended and restated in 2011, further amended November 2012 (incorporated by reference to Exhibit 10.40 of our Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 15, 2013).
+10.40	Enbridge Performance Stock Unit Plan (2007), dated January 1, 2007 (incorporated by reference to Exhibit 10.5 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).
+10.41	Enbridge Performance Stock Unit Plan (2007), as amended November 2012 (incorporated by reference to Exhibit 10.40 of our Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 15, 2013).
10.42	Indenture, dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.5 of our Registration Statement on Form S-4, filed on June 30, 2003).
10.43	Second Supplemental Indenture, dated May 27, 2003, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.7 of our Registration Statement on Form S-4, filed on June 30, 2003).
10.44	Fourth Supplemental Indenture, dated December 3, 2004, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on December 3, 2004).
10.45	Fifth Supplemental Indenture, dated December 3, 2004, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K, filed on December 3, 2004).
10.46	Sixth Supplemental Indenture, dated December 21, 2006, between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on December 21, 2006).
10.47	Seventh Supplemental Indenture, dated April 3, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on April 7, 2008).
10.48	Eighth Supplemental Indenture, dated April 3, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K, filed on April 7, 2008).
10.49	Ninth Supplemental Indenture, dated December 22, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on December 22, 2008).
10.50	Tenth Supplemental Indenture, dated March 2, 2010, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K, filed on March 2, 2010).
10.51	Eleventh Supplemental Indenture, dated September 13, 2010, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K, filed on September 13, 2010).
10.52	Twelfth Supplemental Indenture, dated September 15, 2011, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K, filed on September 15, 2011).
10.53	Indenture for Subordinated Debt Securities, dated September 27, 2007, between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K, filed on September 28, 2007).

Exhibit Number	Description
10.54	First Supplemental Indenture to the Indenture, dated September 27, 2007, between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (including form of Note) (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on September 28, 2007).
10.55	Replacement Capital Covenant, dated September 27, 2007, by Enbridge Energy Partners, L.P. in favor of the debt holders designated therein (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on September 28, 2007).
10.56	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of our Current Report on Form 8-K, filed on February 10, 2005).
10.57	Class A Common Unit Purchase Agreement, dated November 17, 2008, between the Partnership and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on November 18, 2008).
10.58	International Joint Tariff Agreement, dated May 6, 2011, by and between Enbridge Pipelines Inc. and Enbridge Energy, Limited Partnership (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 29, 2011).
10.59	Credit Agreement, dated September 26, 2011, between the Partnership, as Borrower, and Bank of America, N.A., as Administrative Agent and the other lenders a party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on September 29, 2011).
10.60	First Amendment to Credit Agreement, dated as of September 30, 2011, between the Partnership, as Borrower, the lenders parties thereto, and Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q, filed on November 1, 2012).
10.61	Extension Agreement and Second Amendment to Credit Agreement, as of September 26, 2012, between the Partnership, as Borrower, the lenders parties thereto, and Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q, filed on November 1, 2012).
10.62	Extension Agreement and Third Amendment to Credit Agreement, dated as of October 28, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q, filed on October 31, 2013).
10.63	Fourth Amendment to Credit Agreement, dated as of December 23, 2013, Enbridge Energy Partners, L.P., the lenders parties thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.82 of our Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 18, 2014).
10.64	Extension Agreement and Fifth Amendment to Credit Agreement, dated as of October 6, 2014, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on October 10, 2014).
10.65	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, 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 to our of our Current Report on Form 8-K, filed on November 19, 2013).
10.66	Extension Agreement And Sixth Amendment To Credit Agreement dated as of October 23, 2015 by and among Enbridge Energy Partners, L.P., the lender parties thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on October 27, 2015).
10.67	Credit Agreement (364-Day) dated as of March 9, 2015, by and among Enbridge Energy Partners, L.P. and Enbridge (U.S.) Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on March 9, 2015).

Exhibit Number	Description
10.68	Subordination Agreement dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., other obligors from time to time party thereto, Enbridge Energy Partners, L.P., and certain of its subsidiaries and affiliates from time to time party thereto in favor of the holders from time to time of the Notes (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on October 6, 2014).
10.69	Amended and Restated Subordination Agreement Subordination Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the other credit parties from time to time party thereto and Enbridge Energy Partners, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on October 6, 2014).
10.70	Amended and Restated Allocation Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., Enbridge Inc., Enbridge Energy Partners, L.P. and Enbridge Income Fund Holdings Inc. (incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K, filed on November 19, 2013).
10.71	Amended and Restated Limited Liability Company Agreement of North Dakota Pipeline Company LLC, dated as of November 25, 2013, by and between Enbridge Energy Partners, L.P. and Williston Basin Pipe Line LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on December 2, 2013).
10.72	Operating and Construction Management Agreement, dated as of November 25, 2013, by and between North Dakota Pipeline Company LLC and Enbridge (U.S.) Inc. (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on December 2, 2013).
10.73	Credit Agreement dated as of July 6, 2012, by and among the Partnership, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on February 14, 2013).
10.74	Amendment No. 1 to Credit Agreement, dated as of February 8, 2013, by and among the Partnership, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on February 14, 2013).
10.75	Amendment No. 2 to Credit Agreement and Extension and Increase Agreement, dated as of July 3, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on July 5, 2013).
10.76	Amendment No. 2 to Credit Agreement and Extension Agreement, dated as of September 3, 2015, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the subsidiary guarantors party thereto, the lenders party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on September 9, 2015).
10.77	Incremental Commitment Activation Notice to Credit Agreement, dated July 24, 2013, between the Partnership, the Borrower, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.8 of our Quarterly Report on Form 10-Q, filed on July 31, 2013).
10.78	New Lender Supplement to Credit Agreement, dated July 24, 2013, between the Partnership, the Borrower, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.8 of our Quarterly Report on Form 10-Q, filed on July 31, 2013).

Exhibit Number	Description
10.79	Amendment No. 3 to Credit Agreement, dated as of October 28, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q, filed on October 31, 2013).
10.80	Amendment No. 4 to Credit Agreement, dated as of December 23, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.81 of our Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 18, 2014).
10.81	Amendment No. 5 to Credit Agreement and Extension and Decrease Agreement, dated as of July 3, 2014, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on July 8, 2014).
10.82	Amendment No. 6 to Credit Agreement and Extension and Decrease Agreement, dated as of July 2, 2015, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on July 8, 2015).
10.83	Incremental Commitment Activation Notice, dated as of August 7, 2015, by and among Enbridge Energy Partners, L.P., BNP Paribas and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on August 13, 2015).
10.84	New Lender Supplement, dated as of August 7, 2015, by and among Enbridge Energy Partners, L.P., BNP Paribas and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on August 13, 2015).
10.85	Option Interests Purchase Agreement, dated as of June 28, 2013, between Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on July 5, 2013).
10.86	Form of Indemnification Agreement by Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q, filed on October 30, 2015).
10.87	Form of Indemnification Agreement, and Schedule of Omitted Agreements (incorporated by reference to Exhibit 10.6 of our Quarterly Report on Form 10-Q/A, filed on August 6, 2013).
10.88	Form of Indemnification Agreement by Enbridge Energy Company, Inc. together with a schedule of individuals who entered into an agreement in substantially the same form and the date of the agreement. (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed on October 30, 2015)
10.89	Form of Guarantee, and Schedule of Omitted Agreement (incorporated by reference to Exhibit 10.7 of our Quarterly Report on Form 10-Q/A, filed on August 6, 2013).
10.90	Registration Rights Agreement, dated as of May 7, 2013, by and between the Partnership and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on May 13, 2013).
10.91	Purchase and Sale Agreement by and between Enbridge Energy Partners, L.P. and Midcoast Energy Partners, L.P., dated as of June 18, 2014 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on June 19, 2014).
14.1	Code of Ethics for Senior Financial Officers (incorporated by reference to Exhibit 14.1 of our Annual Report on Form 10-K, filed on March 12, 2004).
*21.1	Subsidiaries of the Registrant.
*23.1	Consent of PricewaterhouseCoopers LLP.
*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.

Exhibit Number	Description
*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.
99.1	Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C. (incorporated by reference to Exhibit 99.1 of our Annual Report on Form 10-K, filed February 25, 2005).

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Exhibit 21.1

ENBRIDGE ENERGY PARTNERS, L.P.

Subsidiaries of the Registrant

Company Name	State of Incorporation/ Formation/Organization
Bakken Pipeline Company LLC	Delaware
Bakken Pipeline Company LP	Delaware
ELTM, L.P.	Delaware
Enbridge Energy, Limited Partnership	Delaware
Enbridge Energy Marketing, L.L.C.	Delaware
Enbridge G & P (East Texas) L.P.	Texas
Enbridge G & P (North Texas) L.P.	Texas
Enbridge G & P (Oklahoma) L.P.	Texas
Enbridge Gathering (North Texas) L.P.	Texas
Enbridge Holdings (Mississippi) L.L.C.	Delaware
Enbridge Holdings (Texas Systems) L.L.C.	Delaware
Enbridge Liquids Marketing (North Texas) L.P.	Delaware
Enbridge Marketing (North Texas) L.P.	Delaware
Enbridge Marketing (U.S.) L.L.C.	Delaware
Enbridge Marketing (U.S.) L.P.	Texas
Enbridge Operating Services, L.L.C.	Delaware
Enbridge Partners Risk Management, L.P.	Delaware
Enbridge Pipelines (East Texas) L.P.	Texas
Enbridge Pipelines (Lakehead) L.L.C.	Delaware
Enbridge Pipelines (North Texas) L.P.	Texas
Enbridge Pipelines (Oklahoma Transmission) L.L.C.	Delaware
Enbridge Pipelines (Ozark) L.L.C.	Delaware
Enbridge Pipelines (Texas Gathering) L.P.	Delaware
Enbridge Pipelines (Texas Intrastate) L.P.	Texas
Enbridge Pipelines (Texas Liquids) L.P.	Texas
Enbridge Pipelines (Wisconsin) Inc.	Wisconsin
Enbridge Rail (North Dakota) L.P.	Delaware
Enbridge Storage (Cushing) L.L.C.	Delaware
Enbridge Storage (North Dakota) L.L.C.	Delaware
H&W Pipeline, L.L.C.	Alabama
Midcoast Energy Partners, L.P.	Delaware
Midcoast Holdings, L.L.C.	Delaware
Midcoast OLP GP, L.L.C.	Delaware
Midcoast Operating, L.P.	Texas
North Dakota Pipeline Company LLC	Delaware
Tri-State Holdings, LLC	Michigan

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (333-202292) of Enbridge Energy Partners, L.P. of our report dated February 17, 2016 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 17, 2016

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 Enbridge Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 17, 2016

By: /s/ Mark A. Maki

Mark A. Maki
President and Principal Executive Officer
Enbridge Energy Management, L.L.C.,
(as delegate of 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 Enbridge Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 17, 2016

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C.
(as delegate of the General Partner)

Exhibit 32.1

CERTIFICATION 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 of the United States Code

The undersigned, being the Principal Executive Officer of Enbridge Energy Management, L.L.C., as delegate of the general partner of Enbridge 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, 2015 (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 17, 2016

By: /s/ Mark A. Maki

Mark A. Maki
President and Principal Executive Officer
Enbridge Energy Management, L.L.C.,
(as delegate of the General Partner)

Exhibit 32.2

CERTIFICATION 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 of the United States Code

The undersigned, being the Principal Financial Officer of Enbridge Energy Management, L.L.C., as delegate of the general partner of Enbridge 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, 2015 (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 17, 2016

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C.,
(as delegate of the General Partner)