EnLink Midstream, LLC
Form 10-K
February 20, 2015

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

Form 10-K

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

For the fiscal year ended December 31, 2014

OR

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

For the transition period from to

Commission file number: 001-36336

ENLINK MIDSTREAM, LLC
(Exact name of registrant as specified in its charter)

Delaware (State of organization)	46-4108528 (I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS DALLAS, TEXAS (Address of principal executive offices)	75201 (Zip Code)

(Registrant's telephone number, including area code)
(214) 953-9500

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited Liability Company Interests	The New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None.

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

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

Indicate by check mark whether 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 ý No o

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 ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

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

smaller reporting
company)

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

The aggregate market value of the Common Units representing limited liability company interests held by non-affiliates of the registrant was approximately $1.9 billion on June 30, 2014, based on $41.66 per unit, the closing price of the Common Units as reported on The New York Stock Exchange on such date.

At February 11, 2015, there were 164,141,435 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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ENLINK MIDSTREAM, LLC
PART I
Item 1. Business
General
EnLink Midstream, LLC ("ENLC" or the "Company") is a Delaware limited liability company formed in October 2013. Effective as of March 7, 2014, EnLink Midstream, Inc. ("EMI") merged with and into a wholly-owned subsidiary of the Company, and Acacia Natural Gas Corp I, Inc. ("New Acacia"), formerly a wholly-owned subsidiary of Devon Energy Corporation ("Devon"), merged with and into a wholly-owned subsidiary of the Company (collectively, the "mergers"). Pursuant to the mergers, each of EMI and New Acacia became wholly-owned subsidiaries of the Company and the Company became publicly held. EMI owns common units representing an approximate 7% limited partner interest in EnLink Midstream Partners, LP (the "Partnership") as of December 31, 2014 and also owns EnLink Midstream Partners GP, LLC (the "General Partner"). New Acacia directly owns a 50% limited partner interest in EnLink Midstream Holdings, LP ("Midstream Holdings") as of December 31, 2014, which was a wholly-owned subsidiary of Devon. Concurrently with the consummation of the mergers, a wholly-owned subsidiary of the Partnership acquired the remaining 50% of the outstanding limited partner interest in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings (together with the mergers, the "business combination").
On February 17, 2015, Acacia contributed a 25% interest in Midstream Holdings to the Partnership in exchange for 31.6 million Class D Common Units in the Partnership.
The Company's common units are traded on the New York Stock Exchange ("NYSE") under the symbol "ENLC." Our executive offices are located at 2501 Cedar Springs Rd., Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.enlink.com. In the "Investors" section of our website, we post the following filings as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual reports on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our website are available free of charge.
In this report, the terms "Company" or "Registrant" as well as the terms "ENLC," "our," "we," and "us," or like terms, are sometimes used as references to EnLink Midstream, LLC and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP", the "Partnership," "ENLK" or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries other than Midstream Holdings, and "Midstream Holdings" is sometimes used to refer to EnLink Midstream Holdings, LP itself or to EnLink Midstream Holdings, LP together with EnLink Midstream Holdings GP, LLC and their subsidiaries. References in this report to the "Midstream Entities" refer to EnLink Midstream Partners, LP and Midstream Holdings, together with their consolidated subsidiaries.
ENLINK MIDSTREAM, LLC
Our assets consist of equity interests in the Partnership and Midstream Holdings. The Partnership is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. Midstream Holdings is a partnership held by us and the Partnership engaged in the gathering, transmission and processing of natural gas. Our interests in the Partnership and Midstream Holdings consist of the following:

- 17,431,152 common units representing an aggregate 7% limited partner interest in the Partnership as of December 31, 2014;
- 100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of the Partnership, which owns a 0.7% general partner interest as of December 31, 2014 and all of the incentive distribution rights in the Partnership; and
- 50.0% limited partner interest in Midstream Holdings as of December 31, 2014 and 25% limited partner interest in Midstream Holdings as of February 17, 2015.

Each of the Partnership and Midstream Holdings is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership's or Midstream Holdings' business, as applicable, or to provide for future

distributions.
The incentive distribution rights in the Partnership entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed

in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

We intend to pay distributions to our unitholders on a quarterly basis equal to the cash we receive, if any, from distributions from the Partnership and Midstream Holdings, less reserves for expenses, future distributions and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner's then-current general partner interest, to the extent the board of directors of the general partner exercises its option to do so; and
- cash reserves our board of directors believes are prudent to maintain.

Our ability to pay distributions is limited by the Delaware Limited Liability Company Act, which provides that a limited liability company may not pay distributions if, after giving effect to the distribution, the company's liabilities would exceed the fair value of its assets. While our ownership of equity interests in the General Partner, the Partnership and Midstream Holdings are included in our calculation of net assets, the value of these assets may decline to a level where our liabilities would exceed the fair value of our assets if we were to pay distributions, thus prohibiting us from paying distributions under Delaware law.

ENLINK MIDSTREAM PARTNERS, LP

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. The Partnership's common units are traded on the NYSE under the symbol "ENLK." The Partnership's business activities are conducted through its subsidiary, EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership. The Partnership's executive offices are located at 2501 Cedar Springs Rd., Dallas, Texas 75201, and its telephone number is (214) 953-9500. The Partnership's Internet address is www.enlink.com. The Partnership posts the following filings in the "Investors" section of its website as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: the Partnership's annual reports on Form 10-K; the Partnership's quarterly reports on Form 10-Q; the Partnership's current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on the Partnership's website are available free of charge.

EnLink Midstream GP, LLC, a Delaware limited liability company and our wholly-owned subsidiary, is the Partnership's general partner. The General Partner manages the Partnership's operations and activities.

ENLINK MIDSTREAM HOLDINGS, LP

EnLink Midstream Holdings, LP was formed in 2013 to hold substantially all of the midstream assets formerly held by Devon. We acquired a 50% limited partner interest in Midstream Holdings upon the consummation of the business combination. Midstream Holdings gathers, processes and transports natural gas, primarily for Devon. Midstream Holdings also fractionates NGLs into component NGL products. EnLink Midstream Holdings GP, LLC, a Delaware limited liability company and a wholly-owned subsidiary of the Partnership, is the general partner of Midstream Holdings and manages Midstream Holdings' operations and activities.

The following diagram depicts the organization and ownership of the Company and its subsidiaries as of December 31, 2014:

Definitions

The following terms as defined generally are used in the energy industry and in this document:

/d = per day

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Bbls = barrels
Bboe = billion Boe
Bcf = billion cubic feet
Boe = six Mcf of gas per Bbl of oil
Btu = British thermal units
CO2= Carbon dioxide
CPI= Consumer Price Index
Gal=gallon
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid and natural gas liquids

Capacity volumes at the Partnership's and Midstream Holdings' facilities are measured based on physical volume and stated in cubic feet ("Bcf", "Mcf" or "MMcf"). Throughput volumes are measured based on energy content and stated in British thermal units ("Btu" or "MMBtu"). A volume capacity of 100 MMcf generally correlates to volume capacity of 100,000 MMBtu. Fractionated volumes are measured based on physical volumes and stated in gallons. Crude oil, condensate and brine services volumes are measured based on physical volume and stated in barrels ("Bbls").

Our Operations

The Midstream Entities primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, brine services and marketing, to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 8,800 miles of pipelines, 13 natural gas processing plants, seven fractionators, 3.1 million barrels of NGL cavern storage, 11.0 Bcf of natural gas storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. The Midstream Entities' operations are based in the United States and their sales are derived from external domestic customers.

The Midstream Entities' connect the wells of natural gas producers in their market areas to their gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. The Midstream Entities' purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. The Midstream Entities' operate processing plants that process gas transported to the plants by major interstate pipelines or from their own gathering systems under a variety of fee-based arrangements. The Midstream Entities' provide a variety of crude oil and condensate services, which include crude oil and condensate gathering via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. The Midstream Entities' also have crude oil and condensate terminal facilities in south Louisiana that provide access for crude oil and condensate producers to the premium markets in this area. The Midstream Entities' gas gathering systems consist of networks of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. The Midstream Entities' transmission pipelines primarily receive natural gas from their gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. The Midstream Entities' also have transmission lines that transport NGLs from east Texas and from their south Louisiana processing plants to their fractionators in south Louisiana. Additionally, the Midstream Entities' own an economic interest in an NGL fractionator located at Mont Belvieu, Texas that receives raw mix NGLs from customers, fractionates such raw mix and redelivers the finished products to the customers for a fee. Devon is one of the largest customers of this fractionator. The Midstream Entities' crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barge facilities that, in exchange for a fee, transport oil from a producer site to an end user. The Midstream Entities' processing plants remove NGLs and CO2 from a natural gas stream and their fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

Our assets are comprised of systems and other assets owned by Midstream Holdings, in which we currently hold a 25% interest and in which the Partnership holds the remaining 75% interest, as well as systems and other assets in which the Partnership holds an interest through its wholly-owned subsidiaries, and are located in four primary regions:

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Texas. The Partnership's Texas assets consist of transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.2 Bcf/d and gathering systems with total capacity of approximately 2.8 Bcf/d.

- Oklahoma. Midstream Holdings' Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d and gathering systems with total capacity of approximately 605 MMcf/d.
- Louisiana. The Partnership's Louisiana assets consist of transmission pipelines with a capacity of approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.
- Ohio River Valley. The Partnership's Ohio River Valley ("ORV") operations are an integrated network of assets comprised of a 5,000-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot operation crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks. The Partnership has eight existing brine disposal wells with an injection capacity of approximately 5,000 Bbls/d. Additionally, the Partnership's ORV operations include five condensate stabilization and natural gas compression stations, including two stations under construction, with combined capacities of 19,000 Bbls/d of condensate stabilization and 580 MMcf/d of natural gas compression.

About Devon

Devon (NYSE: DVN) is a leading independent energy company engaged primarily in the exploration, development and production of crude oil, natural gas and NGLs. Devon's operations are concentrated in various onshore areas in the U.S. and Canada. Please see Devon's Annual Report on Form 10-K for the year ended December 31, 2014 for additional information concerning Devon's business.

Our Business Strategies

Our primary business objective is to increase our cash available for distributions to our unitholders over time. We intend to accomplish this objective by having the Partnership and Midstream Holdings execute the following strategies:

- Organic Growth: pursue opportunities around the Midstream Entities' existing footprint. The Midstream Entities expect to grow certain of their systems organically over time by meeting Devon's and their other customers' midstream service needs that result from their drilling activity in the Midstream Entities' areas of operation. The Midstream Entities continually evaluate whether to pursue economically attractive organic expansion opportunities in existing or new areas of operation that allow the Midstream Entities to leverage their existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand for the Midstream Entities' services.
- Growing with Devon: The Midstream Entities expect their relationship with Devon will continue to provide them with significant business opportunities. Devon is a leading North American E&P company with a focus on five core growth areas: Eagle Ford, Permian Basin, Anadarko Basin, Canadian oil sands and the Barnett Shale.
- Dropdowns: maximize opportunities provided by Devon's sponsorship and assets held by the Company. The Midstream Entities plan to execute their growth in part through pursuing accretive dropdown opportunities from Devon and the Company. On February 17, 2015, the Partnership purchased a 25% interest in Midstream Holdings from us, increasing its ownership in Midstream Holdings to 75%, and we expect to give the Partnership the opportunity over time to purchase the remaining interest in Midstream Holdings held by us. ENLC and Devon are parties to a first offer agreement pursuant to which ENLC has a right of first offer with respect to Devon's 50% interest in the Access Pipeline (the "First Offer Agreement"). The Partnership is party to a preferential rights agreement with us and our wholly-owned subsidiary pursuant to which we granted the Partnership a right of first refusal, for a period of 10 years, with respect to Devon's 50% interest in the Access Pipeline transportation system, to the extent in the future we obtain such interest pursuant to a first offer agreement between Devon and us. In addition, if ENLC has the opportunity to exercise its right of first offer for Devon's interest in the Access Pipeline pursuant to the First Offer Agreement, but determines not to exercise such right, ENLC is required to assign such right to the Midstream Entities. Though there is no contractual obligation, the Midstream Entities anticipate being given the opportunity to purchase the Victoria Express Pipeline from Devon in the future. The Midstream Entities also believe there will continue to be significant opportunities as Devon continues to develop its oil and gas production. However, the Midstream Entities cannot be certain that these opportunities will be made available to them, or that they will choose to pursue any such opportunity.

- Acquisitions: pursue strategic and accretive acquisitions. The Midstream Entities pursue strategic and accretive acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and geographic areas of operation.
- Strong Balance Sheet: maintain an investment grade quality financial profile. The Midstream Entities intend to maintain appropriate leverage and other key financial metrics in line with other partnerships in the Midstream Entities'

sector that have received investment grade credit ratings. By maintaining an investment grade quality financial profile, the Midstream Entities believe that they will be able to pursue strategic acquisitions and large growth projects at a lower cost of capital, which enhances their competitiveness.

Our Competitive Strengths

We believe that the Partnership and Midstream Holdings are well-positioned to execute their business strategies and to achieve their business objectives due to the following competitive strengths:

- Devon's sponsorship. The Midstream Entities expect their relationship with Devon will continue to provide them with significant business opportunities. Devon is one of the largest independent oil and gas producers in North America. Devon has a significant interest in promoting the success of the Midstream Entities' business, due to its approximate 70% ownership interest in us and approximate 49% ownership interest in the Partnership.
- Strategically-located assets. The Midstream Entities' assets are strategically located in strategic producing regions with the potential for increasing throughput volume and cash flow generation. The Midstream Entities' assets are in areas consistent with Devon's strategic focus. The Midstream Entities' asset portfolio includes gathering, transmission, fractionation, processing and stabilization systems that are located in areas in which producer activity is focused on crude oil, condensate and NGLs as well as natural gas. The Midstream Entities have developed or are in the process of developing platforms in these areas through organic development and acquisitions.
- Stable cash flows. Approximately 95% of the Midstream Entities' combined cash flows were derived from fee-based services with no direct commodity exposure during 2014. Midstream Holdings has entered into 10-year, fixed-fee gathering and processing agreements with a subsidiary of Devon pursuant to which Midstream Holdings or its subsidiary will provide gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to Midstream Holdings' gathering and processing systems in the Barnett and Cana-Woodford Shales. These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. These agreements also include five-year minimum volume commitments and annual rate escalators. Please read "—Midstream Holdings' Contractual Relationship with Devon." The Midstream Entities will continue to focus on contract structures that reduce volatility and support long-term stability of cash flows.
- Integrated midstream services. The Midstream Entities span the energy value chain by providing natural gas, NGL, crude oil, condensate and water services across a diverse customer base. These services include gathering, compressing, treating, processing, transporting, storing and selling natural gas, producing, fractionating, transporting, storing and selling NGLs, and gathering, transporting, storing and trans-loading crude oil and condensate. The Midstream Entities believe their ability to provide all of these services gives them an advantage in competing for new opportunities because they can provide substantially all services that producers, marketers and others require to move natural gas, NGLs, crude oil and condensate from the wellhead to the market on a cost-effective basis.
- Financial flexibility to pursue expansion and acquisition opportunities. The Midstream Entities believe their stable cash flows, strong balance sheet and access to debt and equity capital markets provide them with the financial flexibility to competitively pursue acquisition and expansion opportunities and to execute their strategy across capital market cycles.
- Experienced management team. The Midstream Entities believe their management team has a proven track record of creating value through the development, acquisition, optimization and integration of midstream assets. The Midstream Entities' management team has an average of over 20 years of experience in the energy industry. The Midstream Entities believe this team provides them with a strong foundation for evaluating growth opportunities and operating their assets in a safe, reliable and efficient manner.

We believe that the Midstream Entities will leverage their competitive strengths to successfully implement their strategy; however, their business involves numerous risks and uncertainties that may prevent the Midstream Entities from achieving their primary business objective. For a more complete description of the risks associated with the Midstream Entities' business, please see "Item 1A. Risk Factors."

Midstream Holdings' Contractual Relationship with Devon

Upon the consummation of the business combination, Midstream Holdings entered into a 10-year transportation contract with Devon for the Acacia transmission system as well as the following additional fee-based agreements with Devon:

Contract	Contract Term (Years)	Minimum Gathering Volume Commitment (MMcf/d)	Minimum Processing Volume Commitment (MMcf/d)	Minimum Volume Commitment Term (Years)	Annual Rate Escalators
Bridgeport gathering and processing contract (1)	10	850	650	5	CPI
East Johnson County gathering contract	10	125	—	5	CPI
Northridge gathering and processing contract (2)	10	40	40	5	CPI
Cana gathering and processing contract	10	330	330	5	CPI

(1) The Bridgeport gathering and processing contract includes volume commitments to the Bridgeport processing facility as well as the Bridgeport gathering systems.

(2) On December 1, 2014, Devon Gas Services (“Gas Services”) assigned its 10-year gathering and processing agreement to Linn Exchange Properties, LLC (“Linn Energy”), which is a subsidiary of Linn Energy, LLC, in connection with Gas Services' divestiture of certain of its southeastern Oklahoma assets. Accordingly, on December 1, 2014, Linn Energy assumed all of Gas Services' obligations under the agreement, which remains in full force and effect. This agreement relates to production dedicated to our Northridge assets in southeastern Oklahoma.

Recent Growth Developments

Organic Growth

Ohio River Valley Condensate Pipeline and Condensate Stabilization Facilities. In August 2014, the Partnership announced plans to construct a new 45-mile, eight-inch condensate pipeline and six natural gas compression and condensate stabilization facilities that will service major producer customers in the Utica Shale, including Eclipse Resources. As a component of the project, the Partnership has entered into a long-term, fee-based agreement under which Eclipse Resources will receive compression and stabilization services and has agreed to sell stabilized condensate to the Partnership.

The new-build stabilized condensate pipeline will connect to the Partnership's existing 200-mile pipeline in the ORV, providing producer customers in the region access to premium market outlets through the Partnership's barge facility on the Ohio River and rail terminal in Ohio. The pipeline, which is expected to be complete in the second half of 2015, is expected to have an initial capacity of approximately 50,000 Bbls/d with potential to expand.

The Partnership will also build and operate six natural gas compression and condensate stabilization facilities in Noble, Belmont, and Guernsey counties in Ohio. Upon completion, the facilities will have a combined capacity of approximately 560 MMcf/d of natural gas compression and approximately 41,500 Bbls/d of condensate stabilization. The first two compression and condensate stabilization facilities began operations during the fourth quarter of 2014 and the remaining four facilities are expected to be operational by the end of 2015.

In support of the project, the Partnership plans to leverage and expand its existing midstream assets in the region, including increasing condensate storage capacity and handling capabilities at its barge terminal on the Ohio River. The Partnership will add approximately 130,000 barrels of above ground storage, bringing its total storage capacity at the barge facility to over 360,000 barrels.

Marathon Petroleum Joint Venture. The Partnership has entered into a series of agreements with MPL Investment LLC, a subsidiary of Marathon Petroleum Corporation (“Marathon Petroleum”), to create a 50/50 joint venture named Ascension Pipeline Company, LLC. This joint venture will build a new 30-mile NGL pipeline connecting the Partnership’s existing Riverside fractionation and terminal complex to Marathon Petroleum’s Garyville refinery located on the Mississippi River. The bolt-on project to the Partnership’s Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, the Partnership will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

Cajun-Sibon Phases I and II. In Louisiana, the Partnership has transformed its business that historically has been focused on processing offshore natural gas to a business that is now focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market historically has relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II now work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

The pipeline expansion and the Eunice fractionation expansion under Phase I were completed and commenced operation in November 2013. Phase II of the Cajun-Sibon expansion, which was completed and commenced operation in September 2014, increased the Cajun-Sibon pipeline capacity by an additional 50,000 Bbls/d to approximately 130,000 Bbls/d and added a new 100,000 Bbl/d fractionator at the Partnership's Plaquemine gas processing complex. The throughput of the pipeline averaged 109,900 Bbls/d during the fourth quarter of 2014. The Partnership's fractionators in south Louisiana averaged approximately 98,300 Bbls/d during the fourth quarter of 2014.
The Partnership believes the Cajun-Sibon project represents a tremendous growth step by leveraging its Louisiana assets and also by creating a significant platform for continued growth of the Partnership's NGL business. The Partnership believes this project, along with existing assets, will provide a number of additional opportunities to grow this business, including expanding market optionality and connectivity, upgrading products, expanding rail imports, exporting NGLs and expanding fractionation and product storage capacity.
Bearkat Natural Gas Gathering and Processing System. In September 2014, the Partnership completed construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin called Bearkat. The natural gas processing complex includes treating, processing and gas takeaway solutions for regional producers. The project, which is fully owned by the Partnership, is supported by a 10-year, fee-based contract.
Bearkat is strategically located near the Partnership's existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant has an initial capacity of 60 MMcf/d, increasing the Partnership’s total operational processing capacity in the Permian to approximately 115 MMcf/d. The Partnership also completed construction of a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan counties.
During 2014, the Partnership constructed a new 35-mile, 12-inch diameter high-pressure pipeline to provide critical gathering capacity for the Bearkat natural gas processing complex. The pipeline has an initial capacity of approximately 100 MMcf/d and provides gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The pipeline commenced operation in the fourth quarter of 2014.
Growing with Devon
West Texas Expansion. The Partnership is expanding its natural gas gathering and processing system in the Permian Basin by constructing a new natural gas processing plant and expanding the Partnership's rich gas gathering system. The new 120 MMcf/d gas processing plant will be strategically located on the north end of the Partnership's existing midstream assets and will offer additional gas processing capabilities to producer customers in the region, including Devon. Due to the impact from the current commodity environment and a shift in producers’ drilling expectations, we are delaying construction on the processing plant until late 2015. Upon completion, the Partnership's total operated processing capacity in the region will be approximately 240 MMcf/d.
As a part of the expansion, the Partnership is a party to a long-term, fee-based agreement with Devon Energy to provide gathering and processing services for over 18,000 acres under development in Martin County. The Partnership constructed multiple low pressure gathering pipelines and a new 23-mile, 12-inch high pressure gathering pipeline that will tie into the Bearkat natural gas gathering system. The new pipelines commenced operation in January of 2015.
Drop Downs
Midstream Holdings Drop Down. On February 17, 2015, Acacia, a wholly-owned subsidiary of ENLC, sold a 25% limited partner interest in Midstream Holdings (the “Transferred Interest”) to the Partnership in a drop down transaction (the “EMH Drop Down”). As consideration for the Transferred Interest, the Acacia received 31.6 million Class D Common Units in the Partnership. After giving effect to the EMH Drop-Down, the Partnership indirectly owns a 75% limited partner interest in Midstream Holdings, with Acacia owning the remaining 25% limited partner interest in Midstream Holdings.
E2 Investment. On October 10, 2014, we purchased 100% of Class A units and 50% of Class B Units of E2 Appalachian Compression, LLC owned by E2 management for $7.0 million and $5.5 million, respectively. E2 constructed three natural gas compressor stations and condensate stabilization facilities located in Noble and Monroe counties in the southern portion of the Utica Shale play in Ohio.
E2 Drop Down. On October 22, 2014, EMI, a wholly-owned subsidiary of ENLC, sold 100% of the Class A Units and 50% of the Class B Units (collectively, the “E2 Appalachian Units”) in E2 Appalachian Compression, LLC (“E2 Appalachian”), and 93.7% of the Class A Units (the “Energy Services Units” and, together with the E2 Appalachian

Units, the “Purchased Units”) in E2 Energy Services, LLC (“Energy Services” and together with E2 Appalachian “E2”), to the Partnership. The total consideration paid by the Partnership to EMI for the Purchased Units included (i) $13.0 million in cash for the Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in the Partnership for the E2 Appalachian Units. The remaining 50% of the Class B Units in E2 Appalachian are owned by members of the E2 Appalachian management team and are designed to provide such management team members with equity incentives.

Acquisitions

Coronado Midstream. On February 1, 2015, the Partnership entered into an agreement with Reliance Midstream, LLC, a Texas limited liability company ("Reliance"), Windsor Midstream LLC, a Delaware limited liability company ("Windsor"), Wallace Family Partnership, LP, a Texas limited partnership ("Wallace"), and Ted Collins, Jr., an individual residing in Midland, Texas ("Collins" and, collectively with Reliance, Windsor and Wallace, the "Sellers," and each, a "Seller"), and Reliance, in its capacity as representative of the Sellers, to acquire all of the equity interests in Coronado Midstream Holdings LLC, the parent company of Coronado Midstream LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.0 million in cash and equity, subject to certain adjustments. Coronado operates three cryogenic gas processing plants and a gas gathering system in the North Midland Basin including approximately 270 miles of gathering pipelines, 175 MMcf/d of processing capacity and 35,000 horsepower of compression. The Coronado system is underpinned by long-term contracts, which include the dedication of production from over 190,000 acres.

LPC Crude Oil Marketing. On January 31, 2015, the Partnership, through one of its wholly owned subsidiaries, acquired LPC Crude Oil Marketing LLC ("LPC"), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $100.0 million. LPC is an integrated crude oil logistics service provider with operations throughout the Permian Basin. LPC's integrated logistics services are supported by 41 tractor trailers, 13 pipeline injection stations and 67 miles of crude oil gathering pipeline.

Natural Gas Pipeline Assets. On November 1, 2014, the Partnership acquired from affiliates of Chevron Corporation certain Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana, for $234.0 million, subject to certain adjustments. These natural gas pipeline assets include the following:

- Bridgeline System: approximately 990 miles of natural gas pipelines in southern Louisiana with a total system capacity of approximately 900 MMcf/d;
- Sabine Pipeline: approximately 130 miles of natural gas pipelines in Texas and southern Louisiana with a total capacity of approximately 300 MMcf/d;
- Chandeleur System: approximately 215 miles of offshore Mississippi and Alabama pipelines with a total capacity of approximately 300 MMcf/d;
- Storage Assets: three caverns located in southern Louisiana with a combined working capacity of approximately 11.0 Bcf of natural gas, including two near Sorrento, LA with a capacity of approximately 4.0 Bcf and one inactive cavern near Napoleonville, LA with a capacity of approximately 7.0 Bcf; and
- Henry Hub: ownership and management of the title tracking services offered at the Henry Hub, the delivery location for the New York Mercantile Exchange (the "NYMEX") natural gas futures contracts. Henry Hub is connected to 13 major interstate and intrastate natural gas pipeline and storage systems.

Our Assets

The Midstream Entities' assets consist of gathering systems, transmission pipelines, processing facilities, fractionation facilities, stabilization facilities, storage facilities and ancillary assets. The following tables provide information about our assets as of and for the year ended December 31, 2014:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (1) (HP)	Year Ended December 31, 2014 Estimated Capacity (MMcf/d)		Average Throughput (Thousands of MMBtu/d)	
Texas Assets:						
Partnership Assets ^	895	131,834	1,715		958,300	
Midstream Holdings Assets*	3,267	262,000	2,330		1,999,600	
Oklahoma Assets:						
Cana System*	340	87,499	530		414,000	
Northridge System*	140	17,895	75		57,000	
Louisiana Assets:						
LIG System^ (2)	3,320	78,648	3,975		615,000	
South Louisiana Assets^	600	—	—	(3)	—	(4)
Total	8,562	577,876	8,625		4,043,900	

^ Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which the Partnership held a 50% interest as of December 31, 2014 and a 75% interest as of February 17, 2015.

(1) Includes power generation units.

(2) Includes natural gas pipelines acquired from Chevron Corporation on November 1, 2014. Average throughput volumes reflect throughput for the period from November 1, 2014 through December 31, 2014.

(3) The Partnership's South Louisiana assets also have estimated capacity for liquid pipeline transportation of 130 MBbls/d.

(4) The Partnership's South Louisiana Cajun-Sibon liquids pipeline, including the Cajun-Sibon II expansion which commenced operations in late September 2014, had an average throughput of 72,900 Bbls/d for the year ended December 31, 2014.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2014 Average Throughput (MMBtu/d)
Texas Assets		
Partnership Assets^	369	357,100
Midstream Holdings Assets*	790	788,700
Oklahoma Assets		
Cana System*	350	368,400
Northridge System*	200	73,400
Louisiana Assets		
LIG Assets^	335	193,400
South Louisiana Assets^	1,375	354,000
Total	3,419	2,135,000

^ Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which the Partnership held a 50% interest as of December 31, 2014 and a 75% interest as of February 17, 2015.

Fractionation Facilities	Estimated NGL Fractionation Capacity (MBbls/d)	Average Throughput (MBbls/d)	
Texas Assets			
Partnership Assets^	15	—	(2)
Midstream Holdings Assets*	15	—	(2)
Louisiana Assets			
LIG Assets^	11	5	
South Louisiana Assets^	183	116	
Gulf Coast Fractionators (1)	56	44	
Total	280	165	

^ Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which the Partnership held a 50% interest as of December 31, 2014 and a 75% interest as of February 17, 2015.

(1) Volumes are shown net of Midstream Holdings' net contractual right to the burdens and benefits of a 38.75% economic interest in Gulf Coast Fractionators held by Devon.

(2) The Partnership is in the process of connecting its Texas fractionation facility to its Deadwood processing plant in the Permian Basin and the Midstream Holdings fractionation facility is connected to its Bridgeport processing plant. These fractionation facilities will provide operational flexibility for the related processing plants, but are not the primary fractionation facilities for the NGLs produced by the processing plants. Under the Partnership's current contracts, it does not earn fractionation fees for operating these facilities so throughput volumes through these facilities are not captured on a routine basis and are not significant to its operating margins.

Texas Assets. The Midstream Entities' Texas assets consist of systems and other assets owned by Midstream Holdings, in which we own a 25% interest as of February 17, 2015 and in which the Partnership holds the remaining 75% interest, as well as systems and other assets in which the Partnership holds an interest through its wholly-owned subsidiaries. These assets include transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.2 Bcf/d and gathering systems with total capacity of approximately 2.8 Bcf/d.

- Transmission Systems. The Midstream Entities' transmission systems in Texas include approximately 260 miles of pipeline with an aggregate capacity of approximately 1.3 Bcf/d and consist of the following:

- North Texas Pipeline. The Partnership's North Texas Pipeline ("NTPL") is a 140-mile pipeline extending from an area near Fort Worth, Texas to a point near Paris, Texas and connects production from the Barnett Shale to markets in north Texas accessed by the Natural Gas Pipeline Company of America, LLC, Kinder Morgan, Inc., Houston Pipeline Company, L.P., Atmos Energy Corporation and Gulf Crossing Pipeline Company, LLC. The NTPL has approximately 375 MMcf/d of capacity and 18,960 horsepower of compression and, for the period March 7, 2014 through December 31, 2014, the average throughput on the NTPL was approximately 338,000 MMBtu/d.

- Acacia transmission system. The Acacia transmission system, which is owned by Midstream Holdings, is a 120-mile pipeline that connects production from the Barnett Shale to markets in north Texas accessed by Atmos Energy, Brazos Electric, Enbridge Energy Partners, Energy Transfer Partners, Enterprise Product Partners and GDF Suez. The Acacia transmission system has approximately 920 MMcf/d of capacity and 17,000 horsepower of compression and, for the year ended December 31, 2014, average throughput was approximately 733,900 MMBtu/d. Devon is the Acacia transmission system's only customer and has entered into a 10-year fixed-fee transportation agreement that covers transmission services on the Acacia transmission pipeline and includes annual rate escalators.

- Processing and Fractionation Facilities. The Midstream Entities' processing facilities in Texas include six gas processing plants with total processing throughput that averaged 1,145,749 MMBtu/d for the year ended December 31, 2014 and our 38.75% interest in GCF and consist of the following:

- Bridgeport processing facility. The Bridgeport natural gas processing facility, located in Wise County, Texas, approximately 40 miles northwest of Fort Worth, Texas, is owned by Midstream Holdings and is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants that have a total of 790 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity, respectively. For the year ended December 31, 2014, throughput volumes at the Bridgeport processing facility averaged 788,700 MMBtu/d of natural gas. Devon is the Bridgeport facility's largest customer with approximately 717,700 MMBtu/d of natural gas processed for the year ended December 31, 2014, which represented approximately 91% of the total volumes processed at the facility during such period. In March 2014, Devon and Midstream Holdings entered into a 10-year, fixed-fee processing agreement pursuant to which Midstream Holdings provides processing services for natural gas delivered by Devon to the Bridgeport processing facility. This contractual arrangement includes a five-year minimum volume commitment from Devon of 650 MMcf/d of natural gas delivered to the Bridgeport processing facility as well as annual rate escalators.

- Silver Creek processing complex. The Partnership's Silver Creek processing complex, located in Weatherford, Azle and Fort Worth, Texas, includes three processing plants. The Partnership's Silver Creek plants have a total of 280 MMcf/d of processing capacity, with the Azle Plant, Silver Creek Plant and Goforth Plant accounting for 50 MMcf/d, 200 MMcf/d and 30 MMCf/d of processing capacity, respectively. For the period March 7, 2014 through December 31, 2014, throughput volumes at the Silver Creek processing facility averaged 283,600 MMBtu/d of natural gas.

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Permian Basin assets. The Partnership's Permian Basin assets consist of its Deadwood natural gas processing plant, its Bearkat natural gas processing plant and gathering facilities, and its Mesquite Terminal fractionator. The Partnership has a 50% undivided working interest in the Deadwood processing facility which is located in Glasscock County, Texas. The Deadwood plant is supported by acreage dedication from a major producer in the Permian Basin. The Deadwood processing facility has a total capacity of 58 MMcf/d and total processing throughput that averaged 71,000 MMBtu/d for the period March 7, 2014 through December 31, 2014. The Mesquite Terminal, which has 15,000 BBls/d of fractionation capacity, is located in Midland County and serves as a terminal for third-party raw-make NGLs. The Partnership is also transloading crude oil and condensate at this facility. The Bearkat facility came online in the third quarter of 2014 and consists of a natural gas processing plant with condensate stabilization. The Bearkat plant has a total capacity of 60MMcf/d, and is supplied from approximately 90 miles of high pressure gathering pipelines and 6 compressor stations. The high pressure gathering system has a capacity of approximately 240 MMcf/d. The Bearkat plant averaged 3,000 MMBtu/d for December 2014, which was the first full month of operations.

- Gulf Coast Fractionators. Midstream Holdings is entitled to receive the economic benefits and burdens of the 38.75% interest in Gulf Coast Fractionators held by Devon, with the remaining interests owned 22.50% by Phillips 66 and 38.75% by Targa Resources Partners. Gulf Coast Fractionators owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. Phillips 66 is the operator of the fractionator. Gulf Coast Fractionators receives raw mix NGLs from customers, fractionates the raw mix and redelivers the finished products to the customers for a fee. The facility has a capacity of approximately 145 MBbls/d. The plant fractionated 44,000 Bbls/d of liquids during 2014.

- Gathering Systems. The Midstream Entities' gathering systems in Texas include approximately 3,902 miles of pipeline with total throughput of approximately 1,866,000 MMBtu/d for the year ended December 31, 2014 and consist of the following:

- Bridgeport rich gathering system. This rich natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 1,922 miles of pipeline segments with approximately 145,000 horsepower of compression. A substantial majority of the natural gas gathered on the system is delivered to the Bridgeport processing facility. For the year ended December 31, 2014, throughput volumes on the Bridgeport rich gathering system averaged 826,300 MMBtu/d of natural gas. Devon is the largest customer on the Bridgeport rich gathering system with approximately 751,900 MMBtu/d of natural gas gathered for the year ended December 31, 2014, which represented approximately 91% of the total throughput on the system during such period. As described above, Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering agreement pursuant to which Midstream Holdings provides gathering services on the Bridgeport system, which includes a five-year minimum volume commitment from Devon of a combined 850 MMcf/d of natural gas delivered for gathering into the Bridgeport rich and Bridgeport lean gathering systems.

- Bridgeport lean gathering system. This lean natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 935 miles of pipeline segments with approximately 59,000 horsepower of compression. Natural gas gathered on this system is delivered to the Acacia transmission system and intrastate pipelines without processing. For the year ended December 31, 2014, throughput volumes on the Bridgeport lean gathering system averaged 245,900 MMBtu/d of natural gas. Devon is the largest customer on the Bridgeport lean gathering system with approximately 228,700 MMBtu/d of natural gas gathered for the year ended December 31, 2014, which represented approximately 93% of the total throughput on the system during such period. As described above, Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering and processing agreement that covers gathering services on the Bridgeport system.

- East Johnson County gathering system. This natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 290 miles of pipeline segments. Natural gas gathered on this system is delivered to intrastate pipelines without processing. For the year ended December 31, 2014, throughput volumes on the East Johnson County gathering system averaged 193,500 MMBtu/d of natural gas. Devon is the largest customer on the East Johnson County gathering system with approximately 181,900 MMBtu/d of natural gas gathered for the year ended December 31, 2014, which represented approximately 94% of the total throughput on the system during such period. In March 2014, Devon and Midstream Holdings entered into a 10-year, fixed-fee gathering agreement pursuant to which Midstream Holdings provides gathering services on the East Johnson County gathering system, which includes a five-year minimum volume commitment from Devon of 125 MMcf/d of natural gas delivered for gathering into the East Johnson County gathering system as well as annual rate escalators.

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Silver Creek gathering systems. The Partnership's Silver Creek gathering system includes two gathering systems. The Partnership's north Texas gathering system, which we refer to as NTG, consists of approximately 690 miles of gathering lines with approximately 112,900 horsepower of compression and had an average throughput of approximately 608,700 MMBtu/d for the period March 7, 2014 through December 31, 2014. The Denton system consists of approximately 35 miles of gathering lines and had an average throughput of approximately 11,600 MMBtu/d for the period March 7, 2014 through December 31, 2014.

- Howard Energy Partners ("HEP"). HEP owns and operates over 500 miles of pipeline and a 200 MMcf/d processing plant, serving production from the Eagle Ford, Escondido, Olmos, Pearsall and other formations in south Texas and pursues a growth strategy focused on the needs of south Texas producers. HEP's system has 145 MMcf/d of amine treating capacity and more than 9,000 horsepower of compression. In addition, HEP has a 10 MBbls/d stabilizer in Live Oak County and a 220 MBbls/d liquids storage terminal near Brownsville, Texas. As of December 31, 2014, the Partnership owned a 30.6% interest in HEP and accounted for this investment under the equity method of accounting. The Partnership includes its equity investment in HEP in its corporate segment. Alinda Capital Partners owns a 59% capital interest in HEP.

Oklahoma Assets. The Midstream Entities' Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d, gathering systems with total capacity of approximately 605 MMcf/d and a crude oil and condensate stabilization facility. All of the systems and other assets comprising the Oklahoma assets are owned by Midstream Holdings, in which we own a 25% interest and the Partnership holds the remaining 75% interest.

- Cana system. Midstream Holdings' Cana gathering and processing system is located in the Cana-Woodford Shale in West Central Oklahoma and consists of the following:

- Cana processing facilities. Midstream Holdings' Cana processing facilities include a multi-train 350 MMcf/d cryogenic processing plant and a crude oil and condensate stabilization facility. For the year ended December 31, 2014, throughput volumes at the Cana processing facility averaged 368,400 MMBtu/d. The residue natural gas from the Cana processing facility is delivered to Enable Midstream Partners and ONEOK Partners. Devon is the primary customer of the Cana processing facilities and has entered into a 10-year, fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings provides processing services for natural gas delivered by Devon to the Cana processing facility. This contractual arrangement includes a five-year minimum volume commitment from Devon of 330 MMcf/d of natural gas delivered to the processing facility as well as annual rate escalators.

- Cana gathering system. Midstream Holdings' Cana gathering system includes an approximately 340-mile gathering system with approximately 87,500 horsepower of compression. For the year ended December 31, 2014, the Cana system gathered approximately 413,900 MMBtu/d of gas. Devon is the primary customer of the Cana gathering system and, as described above, has entered into a 10-year, fixed-fee gathering agreement with Midstream Holdings pursuant to which Midstream Holdings provides gathering services on the Cana gathering system and that includes a five-year minimum volume commitment from Devon of 330 MMcf/d of natural gas delivered for gathering into the Cana gathering system.

- Northridge system. Midstream Holdings' Northridge gathering and processing system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma and consists of the following:

- Northridge processing plant. Midstream Holdings' Northridge processing plant has 200 MMcf/d of processing capacity. For the year ended December 31, 2014, throughput volumes at the Northridge processing facility averaged 73,400 MMBtu/d. The residue natural gas from the Northridge processing facility is delivered to Centerpoint, Enable Midstream Partners and MarkWest. In August 2014, Linn Energy acquired certain of Devon's southeastern Oklahoma assets and became the largest customer of the Northridge processing facility. In connection with this acquisition Linn Energy assumed Devon's 10-year fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings provides processing services for natural gas delivered to the Northridge processing facility. This contractual arrangement includes a five-year minimum volume commitment of 40 MMcf/d of natural gas delivered to the Northridge processing facility as well as annual rate escalators.

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Northridge gathering system. Midstream Holdings' Northridge gathering system includes an approximate 140-mile gathering system with approximately 17,900 horsepower of compression. For the year ended December 31, 2014, the Northridge system gathered 56,900 MMBtu/d of gas. Linn Energy is the only customer on the Northridge gathering system and, as described above, has entered into a 10-year fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings provides gathering services on the Northridge gathering system. This contract includes a five-year minimum volume commitment from Linn Energy of 40 MMcf/d of natural gas delivered for gathering into the Northridge gathering system.

Louisiana Assets. The Partnership's Louisiana assets consist of transmission pipelines with a capacity of approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.

- LIG Assets. The LIG system includes gathering and transmission systems with total capacity of approximately 4.0 Bcf/d, processing facilities with a total processing capacity of approximately 335 MMcf/d and fractionation facilities with total capacity of 10,800 Bbls/d.

- The LIG gathering and transmission pipeline system is comprised of the 3,320-mile southern system, which has a capacity in excess of 1.5 Bcf/d and approximately 31,318 horsepower of compression, and the 815-mile northern system, which has a capacity of 465 MMcf/d and approximately 47,330 horsepower of compression. The south system has access to both rich and lean gas supplies from onshore production in south central and southeast Louisiana. LIG has a variety of transportation and industrial sales customers in the south, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans. In the north, the LIG system serves the natural gas fields south of Shreveport, Louisiana and extends into the Haynesville Shale gas play in north Louisiana. The Partnership's north Louisiana system is connected to its south Louisiana system and has the capacity to move approximately 145 MMcf/d of gas to our markets in the south. The Partnership's LIG gathering system had an average throughput of approximately 449,700 MMbtu/d for the period March 7, 2014 through December 31, 2014.

- The south system also includes two operating, on-system processing plants, the Partnership's Gibson and Plaquemine plants, with 110 MMcf/d and 225 MMcf/d of processing capacity, respectively. For the period March 7, 2014 through December 31, 2014, throughput volumes on the LIG processing system averaged 193,400 MMBtu/d of natural gas.

- The Plaquemine plant also has a fractionation capacity of 10,800 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine averaged approximately 4,500 Bbls/d for the period March 7, 2014 through December 31, 2014.

- The Gulf Coast gathering and transmission system is comprised of 1,120 miles of onshore systems with a capacity of 1.2 Bcf/d, approximately 37,785 horsepower of compression, underground storage facilities with a storage capacity of 4.2 Bcf of active storage capacity, 7.0 Bcf of inactive storage capacity, and Henry Hub transfer services with a capacity of 2.1 Bcf/d. The onshore system has access to the Gulf Coast and the industrial rich Mississippi River corridor, which is seeing an abundance of new growth in chemical and fertilizer plants. The onshore system had an average throughput of 157,000 MMBtu/d from November 1, 2014 (the date of acquisition) through December 31, 2014. The offshore system is comprised of 215 miles of pipeline with a capacity of 0.3 Bcf/d. The average throughput for the period November 1, 2014 through December 31, 2014 was 8,500 MMBtu/d.

- South Louisiana NGL and Processing Assets. The Partnership's south Louisiana NGL and natural gas processing assets include approximately 600 miles of liquids transport lines, processing and fractionation assets and underground storage.

- Cajun-Sibon Pipeline System. The Cajun-Sibon pipeline system consists of approximately 600 miles of raw make NGL pipelines with a current system capacity of approximately 130,000 Bbls/d. The pipelines transport unfractionated NGLs, referred to as raw make, from areas such as the Liberty, Texas interconnects near Mont Belvieu and from the Partnership's Eunice and Pelican processing plants in south Louisiana to either the Riverside or Eunice fractionators or to third party fractionators when necessary.

- Processing Facilities. The Partnership's processing facilities in south Louisiana include three gas processing plants, of which only one is currently operational, with total processing throughput that averaged 354,000 MMBtu/d for the period March 7, 2014 through December 31, 2014 and two fractionation facilities that averaged 115,500 Bbls/d for the period March 7, 2014 through December 31, 2014.

- Pelican Processing Plant. The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. For the period March 7, 2014 through December 31, 2014, the plant processed approximately 336,000 MMBtu/d of natural gas. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline. This plant has an interconnection with the LIG pipeline allowing us to process natural gas from the LIG system at our Pelican plant when markets are favorable.

- Blue Water Gas Processing Plant. The Partnership operates and owns a 64.29% interest in the Blue Water gas processing plant. The Blue Water plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. The plant has a net capacity with respect to the Partnership’s interest of approximately 300 MMcf/d. The plant is not expected to operate in the future unless fractionation spreads are favorable and volumes are sufficient to run the plant.

- Eunice Processing Plant. The Eunice processing plant is located in south central Louisiana and has a capacity of 475 MMcf/d of natural gas. In August 2013, the Partnership shut down the Eunice processing plant due to adverse economics driven by low NGL prices and low processing volumes, which the Partnership does not see improving in the near future based on forecasted prices.

- Plaquemine Fractionation Facility. The Plaquemine fractionator is located at our Plaquemine gas processing plant complex and is connected to the Partnership's Cajun-Sibon pipeline. The Plaquemine fractionation facility has a capacity of approximately 100,000 Bbls/d, and produces purity ethane and propane for sale by pipeline to long-term markets with the butane and heavier products sent to our Riverside facility for further processing. The plant commenced operations during September and fractionated 49,700 Bbls/d of liquids during the fourth quarter of 2014.

- Eunice Fractionation Facility. The Eunice fractionation facility is located in south central Louisiana. The Eunice fractionation facility has a capacity of 55,000 Bbls/d of liquid products, including ethane, propane, iso-butane, normal butane and natural gasoline, and is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility. The plant fractionated 48,600 Bbls/d for the period March 7, 2014 through December 31, 2014.

- Riverside Fractionation Facility. The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of approximately 28,000 Bbls/d of liquids delivered by the Cajun-Sibon pipeline system from the Eunice and Pelican processing plants or by third-party truck and rail assets. The Riverside fractionator was converted to a butane-and-heavier facility during 2014 in conjunction with the Cajun-Sibon II project. The Riverside facility has above-ground storage capacity of approximately 233,000 Bbls. The loading/unloading facility has the capacity to transload 15,000 Bbls/d of crude oil and condensate from rail cars to barges. Total volumes for fractionated liquids at Riverside averaged 17,200 Bbls/d for the year ended December 31, 2014. During the periods of full operation at Riverside for 2014 (excluding the 65 days of shut down related to the Cajun-Sibon II project completion), the average throughput was 22,000 Bbls/d.

- Napoleonville Storage Facility. The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of 3.2 million barrels of underground storage comprised of two existing caverns. The caverns are currently operated in propane and butane service, and space is leased to customers for a fee.

Ohio River Valley Assets. The Partnership’s ORV operations are an integrated network of assets comprised of a 5,000-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks with a current capacity of 25,000 Bbls/d. Total crude oil and condensate handled averaged approximately 16,300 Bbls/d for the year ended December 31, 2014. The Partnership has eight existing brine disposal wells with an injection capacity of approximately 5,000 Bbls/d and an average disposal rate of 4,700 Bbls/d for the year ended December 31, 2014. Additionally, the Partnership's ORV operations consist of five condensate stabilization and natural gas compression stations with combined capacities of 19,000 Bbls/d of condensate stabilization and 580 MMcf/d of natural gas compression. Currently, three of the five stations are in service and commercial start-up of the two remaining stations is expected in the first half of 2015. The assets are supported by a long-term, fee-based contract with Antero Resources.

Industry Overview

The following diagram illustrates the gathering, processing, fractionation, stabilization and transmission process.

The midstream industry is the link between the exploration and production of natural gas and crude oil and condensate and the delivery of its components to end-user markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas and crude oil and condensate producing wells.

Natural gas gathering. The natural gas gathering process follows the drilling of wells into gas-bearing rock formations. After a well has been completed, it is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression and treating systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Compression. Gathering systems are operated at pressures that will maximize the total natural gas throughput from all connected wells. Because wells produce gas at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver gas into a higher-pressure downstream pipeline. The remaining natural gas in the ground will not be produced if field compression is not installed because the gas will be unable to overcome the higher gathering system pressure. Also, a declining well can continue delivering natural gas if field compression is installed.

Natural gas processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and CO_2, sulfur compounds, nitrogen or helium. Natural gas produced by a well may not be suitable for long-haul pipeline transportation or commercial use and may need to be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems mostly consists of methane and ethane, and moisture and other contaminants have been removed so there are negligible amounts of them in the gas stream. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as

NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream and the removal of contaminants.

NGL fractionation. NGLs are separated into individual, more valuable components during the fractionation process. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized crude oil and condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutene through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

Natural gas transmission. Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, processing plants and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Crude oil and condensate transmission. Crude oil and condensate are transported by pipelines, barges, rail cars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported.

Condensate Stabilization. Condensate stabilization is the distillation of the condensate product to remove the lighter end components, which ultimately creates a higher quality condensate product that is then delivered via truck, rail or pipeline to local markets.

Brine gathering and disposal services. Typically, shale wells produce significant amounts of water that, in most cases, require disposal. Produced water and frac-flowback is hauled via truck transport or is pumped through pipelines from its origin at the oilfield tank battery or drilling pad to the disposal location. Once the water reaches the delivery disposal location, water is processed and filtered to remove impurities and injection wells place fluids underground for storage and disposal.

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oil and condensate production from the developing shale plays in the United States and Canada. In general, the crude oil and condensate rail loading terminals are used to load rail cars and transport the commodity out of developing basins into market rich areas of the country where crude oil and condensate rail unloading terminals are used to unload rail cars and store crude oil and condensate volumes for third parties until the crude oil and condensate is redelivered to premium markets via pipelines, trucks or rail to delivery points.

Balancing Supply and Demand

When the Partnership purchases natural gas, crude oil and condensate, we establish a margin normally by selling it for physical delivery to third-party users. The Partnership can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the NYMEX related to its natural gas purchases. Through these transactions, the Partnership seeks to maintain a position that is balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. The Partnership's policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas, NGLs, crude oil and condensate is highly competitive. The Midstream Entities face strong competition in obtaining natural gas, NGLs, crude oil and condensate supplies and in the marketing and transportation of natural gas, NGLs, crude oil and condensate, as applicable. Their competitors include major integrated and independent exploration and production companies, natural gas producers, interstate and intrastate pipelines, other natural gas, NGLs, crude oil and condensate gatherers and natural gas processors. Competition for natural gas and crude oil and condensate supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. As a result of the relationship between Devon and Midstream Holdings, the Midstream Entities will not compete for the portion of Devon's existing operations subject to existing acreage dedication and for which Midstream Holdings will provide midstream services. For areas where acreage is not dedicated to Midstream Holdings, the Midstream Entities will compete with similar enterprises in providing additional gathering and processing services in its respective areas of operation, which may offer more services or have strong financial resources and access to larger natural gas, NGLs, crude oil and condensate supplies than they do. Competition varies in different geographic areas.

In marketing natural gas, NGLs, crude oil and condensate the Midstream Entities have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas producers, gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly and through affiliates in marketing activities that compete with their marketing operations.

The Midstream Entities face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition increases the cost to acquire existing facilities or businesses and results in fewer commitments and lower returns for new pipelines or other development projects. The Midstream Entities' competitors may have greater financial resources than they possess or may be willing to accept lower returns or greater risks. Competition differs by region and by the nature of the business or the project involved.

Natural Gas, NGL, Crude Oil and Condensate Supply

The Midstream Entities' gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which they believe have ample natural gas and NGL supplies in excess of the volumes required for the operation of these systems. The Partnership's ORV pipeline, terminals, trucks and storage facilities are strategically located in crude oil and condensate producing regions. The Midstream Entities evaluate well and reservoir data that is either publicly available or furnished by producers or other service providers in connection with the construction and acquisition of their gathering systems and assets to determine the availability of natural gas, NGLs, crude oil and condensate supply for their systems and assets and/or obtain a minimum volume commitment from the producer that results in a rate of return on investment. The Midstream Entities do not routinely obtain independent evaluations of reserves dedicated to their systems and assets due to the cost and relatively limited benefit of such evaluations. Accordingly, the Midstream Entities do not have estimates of total reserves dedicated to their systems and assets or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

The Midstream Entities diligently attempt to ensure that they issue credit to only credit-worthy customers. However, the purchase and resale of crude oil and condensate, gas and other products exposes them to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to their overall profitability.

For the year ended December 31, 2014, Devon represented 30.4% of our consolidated revenues and Dow Hydrocarbons & Resources LLC represented 11.0% of our consolidated revenues. No other customer represented greater than 10.0% of our revenue. Midstream Holdings' operations are dependent on the volume of natural gas that Devon provides to us under commercial agreements, which constitutes a substantial portion of their natural gas supply. For the foreseeable future, we expect our profitability to be substantially dependent on Devon. Further, the loss of Dow Hydrocarbons as a customer could have a material impact on our results of operations if we were not able to sell our products to another customer with similar margins because the gross operating margins received from transactions with this customer are material to our total gross operating margin.

Regulation

Interstate Natural Gas Pipelines Regulation. The Midstream Entities own interstate natural gas pipelines that are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA"). Under the NGA, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. FERC regulation extends to such matters as the following:

- rates, services, and terms and conditions of service;
- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- maximum rates payable for certain services;
- the initiation and discontinuation of services;
- internet posting requirements for available capacity, discounts and other matters;
- pipeline segmentation to allow multiple simultaneous shipments under the same contract;
- capacity release to create a secondary market for transportation services;

- relationships between affiliated companies involved in certain aspects of the natural gas business;

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- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

Natural gas companies are prohibited from charging rates that have been determined not to be just and reasonable by the FERC. In addition, the FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates and terms and conditions for the Partnership interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to the FERC’s jurisdiction over rates, existing rates may be challenged by complaint or by action of the FERC under Section 5 of the NGA, and proposed rate increases may be challenged by protest. The outcome of any successful complaint or protest against the Partnership's rates could have an adverse impact on revenues associated with providing transportation service.

For example, one such matter relates to the FERC’s policy regarding allowances for income taxes in determining a regulated entity’s cost of service. The FERC allows regulated companies to recover an allowance for income taxes in rates only to the extent the company or its owners, such as the Partnership's unitholders, are subject to U.S. income tax. This policy affects whom the Partnership allows to own its units, and if it is not successful in limiting ownership of its units to persons or entities subject to U.S. income tax, the Partnership's FERC-regulated rates and revenues for their interstate natural gas pipelines could be adversely affected.

Interstate natural gas pipelines regulated by the FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. The FERC’s standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates (unless the FERC has granted a waiver of such standards). The FERC’s market oversight and transparency regulations require annual reports of purchases or sales of natural gas meeting certain thresholds and criteria and certain public postings of information on scheduled volumes. The FERC’s market manipulation regulations promulgated pursuant to the Energy Policy Act of 2005 (the “EPAct 2005”) make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 (“NGPA”) to give the FERC authority to impose civil penalties for violations of these statutes, up to $1.0 million per day per violation for violations occurring after August 8, 2005. Should the Midstream Entities fail to comply with all applicable the FERC-administered statutes, rules, regulations and orders, they could be subject to substantial penalties and fines.

The Midstream Entities also transport gas in interstate commerce that is subject to FERC jurisdiction under Section 311 of the NGPA. The maximum rates for services provided under Section 311 of the NGPA may not exceed a “fair and equitable rate,” as defined in the NGPA. The rates are generally subject to review every five years by the FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations, the inability to achieve adequate returns on investments in new facilities and the deterrence of future investment or growth of the regulated facilities.

Interstate Liquids Pipelines Regulation. The Partnership owns liquids transportation, storage and other assets in the ORV, including certain assets providing common carrier interstate service subject to regulation by the FERC under the Interstate Commerce Act (“ICA”), the Energy Policy Act of 1992 and related rules and orders. The Partnership’s Cajun-Sibon NGL pipeline is also subject to the FERC regulation as a common carrier under the ICA, the Energy Policy Act of 1992 and related rules and orders.

The FERC regulation requires that interstate liquids pipeline rates and terms and conditions of service, including rates for transportation of crude oil, condensate and NGLs, be filed with the FERC and that these rates and terms and conditions of service be “just and reasonable” and not unduly discriminatory or unduly preferential.

Rates of interstate liquids pipelines are currently regulated by the FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning in 2010, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under the FERC's regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-services approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. the FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, the FERC could limit the Partnership's ability to set rates based on its costs or could order the Partnership to reduce its rates and could require the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. The FERC also has the authority to change the Partnership's terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As the Partnership acquires, constructs and operates new liquids assets and expands its liquids transportation business, the classification and regulation of its liquids transportation services are subject to ongoing assessment and change based on the services the Partnership provides and determinations by the FERC and the courts. Such changes may subject additional services the Partnership provides to regulation by the FERC.

Intrastate Natural Gas Pipeline Regulation. The Midstream Entities' intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

The FERC's anti-manipulation rules apply to non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. As noted above, the FERC's civil penalty authority under EPAct 2005 would apply to violations of these rules to the extent applicable to the Midstream Entities' intrastate natural gas services.

Intrastate NGL Pipeline Regulation. Intrastate NGL and other petroleum pipelines are not generally subject to rate regulation by the FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate NGL and petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. The Midstream Entities own a number of natural gas pipelines that they believe meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

The Midstream Entities are subject to some state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply.

The FERC's anti-manipulation rules apply to non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. As noted above, the FERC's civil penalty authority under EPAct 2005 would apply to violations of these rules to the extent applicable to the Midstream Entities' natural gas gathering services.

Intrastate Natural Gas Storage Regulation. The storage field's injection and withdrawal wells used in association with the Acacia system, along with water disposal wells located at the Bridgeport processing facility, are under the jurisdiction of the Texas Railroad Commission ("TRRC"). Regulatory requirements for these wells involve monthly and annual reporting of the natural gas and water disposal volumes associated with the operation of such wells, respectively. Results of periodic mechanical integrity tests run on these wells must also be reported to the TRRC.

Sales of Natural Gas and NGLs. The prices at which the Midstream Entities sell natural gas and NGLs currently are not subject to federal regulation and, for the most part, are not subject to state regulation. The Midstream Entities' natural gas and NGL sales 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 and NGL industries, most notably interstate natural gas transmission companies and NGL pipeline companies that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes on the Midstream Entities' natural gas and NGL marketing operations, but we do not believe that the Midstream Entities will be affected by any such FERC action in a manner that is materially different from the natural gas and NGL marketers with whom they compete.

Environmental Matters

General. The Midstream Entities' operations involve processing and pipeline services for delivery of hydrocarbons (natural gas, NGLs, crude oil and condensates) from point-of-origin at oil and gas wellheads operated by their suppliers to the Midstream Entities' end-use market customers. The Midstream Entities' facilities include natural gas processing and fractionation plants, natural gas and NGL storage caverns, brine disposal wells, pipelines and associated facilities, fractionation and storage units for NGLs, and transportation and delivery of petroleum. As with all companies in the Midstream Entities' industrial sector, the Midstream Entities' operations are subject to stringent and complex federal, state and local laws and regulations relating to release of hazardous substances or solid wastes into the environment or otherwise relating to protection of the environment. Compliance with existing and anticipated environmental laws and regulations increases the Midstream Entities' overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities, as well as capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures, and obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of temporary or permanent injunctions or construction or operation bans or delays. As part of the regular evaluation of the Midstream Entities' operations, they routinely review and update governmental approvals as necessary.

The continuing trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts the Midstream Entities currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with possible future operations, and the Midstream Entities cannot assure you that we will not incur significant costs and liabilities, including those relating to claims for damage to property and persons as a result of any such upsets, releases or spills. In the event of future increases in environmental costs, the Midstream Entities may be unable to pass on those cost increases to their customers. A discharge of hazardous substances or solid wastes into the environment could, to the extent losses related to the event are not insured, subject the Midstream Entities to substantial expense, including both the cost to comply with applicable laws and regulations and to pay fines or penalties that may be assessed and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to natural resources or property. The Midstream Entities attempt to anticipate future regulatory requirements that might be imposed and plan accordingly to comply with changing environmental laws and regulations and to minimize costs with respect to more stringent future laws and regulations or more rigorous enforcement of existing laws and regulations.

Hazardous Substances and Solid Waste. Environmental laws and regulations that relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water and/or include measures to prevent and control pollution may pose the highest potential cost to our industry sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes and may require investigatory and corrective actions at facilities where such waste may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the federal "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. Potentially liable persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at an off-site location, such as a landfill. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources.

CERCLA also authorizes the U.S. Environmental Protection Agency (“EPA”) and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek recovery of costs they incur from the potentially responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or solid wastes released into the environment. Although petroleum, natural gas and NGLs are excluded from CERCLA’s definition of a “hazardous substance,” in the course of ordinary operations, the Midstream Entities may generate wastes that may fall within the definition of a “hazardous substance.” In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, the Midstream Entities may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such substances have been disposed. The Midstream Entities have not received any notification that they may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state law.

The Midstream Entities also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act ("RCRA"), and/or comparable state statutes. From time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil, condensate and natural gas wastes. Moreover, it is possible that some wastes generated by the Midstream Entities that are currently exempted from the definition of hazardous waste may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Additionally, the Toxic Substances Control Act ("TSCA") and analogous state laws impose requirements on the use, storage and disposal of various chemicals and chemical substances. Changes in applicable laws or regulations may result in an increase in the Midstream Entities' capital expenditures or plant operating expenses or otherwise impose limits or restrictions on our production and operations.
The Midstream Entities currently own or lease, have in the past owned or leased, and in the future may own or lease, properties that have been used over the years for brine disposal operations, crude oil and condensate transportation, natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes may have been disposed of on or under various properties owned, leased or operated by the Midstream Entities during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whose operations and hydrocarbon and waste management practices the Midstream Entities had no control. These properties and wastes disposed thereon may be subject to the Safe Drinking Water Act, CERCLA, RCRA, TSCA and analogous state laws. Under these laws, the Midstream Entities could be required, alone or in participation with others, to remove or remediate previously disposed wastes or property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.
Air Emissions. The Midstream Entities' current and future operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including the Midstream Entities' facilities, and impose various controls together with monitoring and reporting requirements. Pursuant to these laws and regulations, the Midstream Entities may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. The Midstream Entities likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission-related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on the Midstream Entities' financial condition or operating results, and the requirements are not expected to be more burdensome to the Midstream Entities than to any similarly situated company.
In addition, the EPA included Wise County in its January 2012 revision to the Dallas-Ft. Worth ozone nonattainment area for the 2008 revised ozone national ambient air quality standard ("NAAQS"). As a result of this designation, new major sources, meaning sources that emit greater than 100 tons/year of nitrogen oxides ("NOx") and volatile organic compounds ("VOCs"), as well as major modifications of existing facilities resulting in net emissions increases of greater than 40 tons/year of NOx or VOCs, are subject to more stringent new source review ("NSR") pre-construction permitting requirements than they would be in an area that is in attainment with the 2008 ozone NAAQS. NSR pre-construction permits can take twelve to eighteen months to obtain and require the permit applicant to offset the proposed emission increases with reductions elsewhere at a 1.15 to 1 ratio. Devon, Texas industry trade groups and the State of Texas filed petitions for reconsideration with the EPA and a petition for review in the U.S. D.C. Circuit Court of Appeals challenging the nonattainment designation of Wise County under the 2008 ozone NAAQS. The appeal remains pending.
On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules became effective on October 15,

2012. For new or reworked hydraulically-fractured gas wells, the rules require the control of emissions through flaring or reduced emission (or “green”) completions until 2015, when the rules require the use of green completions by all such wells except wildcat (exploratory) and delineation gas wells and low reservoir pressure non-wildcat and non-delineation gas wells. The rules also establish specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. These rules required a number of modifications to our assets and operations.

In October 2012, several challenges to the EPA's April 17, 2012 rules were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The case remains in abeyance. The EPA has since revised certain aspects of the rules and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such proceedings, the rules may be further modified or rescinded or the EPA may issue new rules. The Midstream Entities cannot predict the costs of compliance with any modified or newly issued rules. Additionally, the EPA has signaled its intent to regulate emissions of methane and volatile organic compounds from the oil and gas sector as a measure to implement President Obama's Climate Action Plan. While the EPA has not yet issued a proposed rulemaking, it has released a series of white papers addressing methane reductions from the oil and gas sector. Depending on whether such rules are promulgated and the applicability and restrictions in any promulgated rule, compliance with such rules could result in additional costs, including increased capital expenditures and operating costs for us and for other companies in our industry. While the Midstream Entities are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for the Midstream Entities. Compliance with such rules, as well as any new state rules, may also make it more difficult for the Midstream Entities' suppliers and customers to operate, thereby reducing the volume of natural gas transported through the Midstream Entities' pipelines, which may adversely affect their business.

Climate Change. In December 2009, the EPA determined that emissions of certain gases, commonly referred to as "greenhouse gases," present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under existing provisions of the federal Clean Air Act, that establish Prevention of Significant Deterioration ("PSD") pre construction permits, and Title V operating permits for greenhouse gas emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet "best available control technology" standards for their greenhouse gas emissions established by the states or, in some cases, by the EPA on a case by case basis. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities.

Because regulation of greenhouse gas emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments in greenhouse gas initiatives may affect the Midstream Entities and other companies operating in the oil and gas industry. In addition to these developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against greenhouse gas emissions sources, which may increase the Midstream Entities' litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with greenhouse gas emissions, we cannot predict the financial impact of related developments on the Midstream Entities.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which the Midstream Entities conduct business could adversely affect the availability of, or demand for, the products the Midstream Entities store, transport and process, and, depending on the particular program adopted, could increase the costs of the Midstream Entities' operations, including costs to operate and maintain their facilities, install new emission controls on their facilities, acquire allowances to authorize their greenhouse gas emissions, pay any taxes related to their greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. The Midstream Entities may be unable to recover any such lost revenues or increased costs in the rates the Midstream Entities charge their customers, and any such recovery may depend on events beyond the Midstream Entities' control, including the outcome of future rate proceedings before FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in the Midstream Entities' revenues or increases in their expenses as a result of climate control initiatives could have adverse effects on the Midstream Entities' business, financial position, results of operations and prospects.

Some scientific studies on climate change suggest that adverse weather events may become stronger or more frequent in the future in certain of the areas in which the Midstream Entities operate, although the scientific studies are not unanimous. Due to their location, the Partnership's operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems, while inland operations include areas subject to tornadoes. The Midstream Entities' insurance may not cover all associated losses. The Midstream Entities are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on their business.

Hydraulic Fracturing and Wastewater. The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including NGL related wastes, into state waters or waters of the United States. The EPA and the U.S. Army Corps of Engineers recently proposed a rule to clarify the meaning of the term "waters of the United States." While the practical effects of the proposed rule are ambiguous, many interested parties, including the State of Texas, believe that the proposed rule will expand federal jurisdiction under the Clean Water Act if it is promulgated in its current form as a final rule. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System (“NPDES”) permits and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that the Midstream Entities are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder and that continued compliance with such existing permit conditions will not have a material effect on the Midstream Entities’ results of operations.

The Partnership operates brine disposal wells that are regulated as Class II wells under the federal Safe Drinking Water Act (“SDWA”). The SDWA imposes requirements on owners and operators of Class II wells through the EPA’s Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. The Partnership’s brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the federal SDWA. Compliance with current and future laws and regulations regarding the Partnership’s brine disposal wells may impose substantial costs and restrictions on our brine disposal operations, as well as adversely affect demand for the Partnership’s brine disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. However, some state regulatory agencies have modified their regulations to account for induced seismicity. For example, TRRC rules allow the TRRC to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on the Partnership’s brine disposal operations.

It is common for the Midstream Entities’ customers or suppliers to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by oil and gas producers. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states and localities have been initiated to require or make more stringent the permitting and other regulatory requirements for hydraulic fracturing operations. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. The EPA has also issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of the Midstream Entities’ customers or suppliers to perform hydraulic fracturing. As a result, any increased federal, state or local regulation could reduce the volumes of natural gas that the Midstream Entities’ customers move through their gathering systems which would materially adversely affect the Midstream Entities’ revenues and results of operations.

Endangered Species and Migratory Birds. The Endangered Species Act ("ESA"), Migratory Bird Treaty Act ("MBTA"), and similar state and local laws restrict activities that may affect endangered or threatened species or their habitats or migratory birds. Some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, potentially exposing us to liability for impacts on an individual member of a species or to habitat. The Endangered Species Act can also make it more difficult to secure a federal permit for a new pipeline.

Employee Safety. The Midstream Entities are subject to the requirements of the Occupational Safety and Health Act ("OSHA"), and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that the Midstream Entities' operations are in substantial compliance with the OSHA requirements including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Pipeline Safety Regulations. The Midstream Entities' pipelines are subject to regulation by the U.S. Department of Transportation ("DOT"). DOT's Pipeline Hazardous Material Safety Administration ("PHMSA"), acting through the Office of Pipeline Safety ("OPS"), administers the national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of pipeline facilities. The main bodies of safety regulations that cover the Midstream Entities' operations are set forth at 49 CFR Parts 192 (covering pipelines that transport natural gas) and 195 (pipelines that transport crude oil and condensate, carbon dioxide, NGL and petroleum products). In addition to recordkeeping and reporting requirements, amendments to 49 CFR Part 192 and 195 created the Pipeline Integrity Management in High Consequence Areas requiring operators of transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In January 2012, the President signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 which increases potential penalties for pipeline safety violations, gives new rulemaking authority to DOT with respect to shut-off valves on transmission pipeline facilities constructed or entirely replaced after the rule is promulgated, requires DOT to revise incident notification guidance and imposes new records requirements on pipeline owners and operators. This legislation also requires DOT to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequences areas, but restricts DOT from promulgating expanded integrity management rules during the review period and for a period following submission of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property or the environment. PHMSA issued a final rule effective October 25, 2013 that implemented aspects of the new legislation. Among other things, the final rule increases the maximum civil penalties for violations of pipeline safety statutes or regulations, broadens PHMSA's authority to submit information requests, and provides additional detail regarding PHMSA's corrective action authority. Additionally, PHMSA issued an Advisory Bulletin in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures could significantly increase the Midstream Entities' costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on the Midstream Entities' pipelines. A December 2012 PHMSA Advisory Bulletin provides further clarity on the reporting requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, describing a general requirement that pipeline owners or operators report an exceedance of the maximum allowable operating pressure or allowable build-up for pressure-limiting or control devices within five days of the date that the exceedance occurs. At the state level, several states have passed legislation or promulgated rulemaking dealing with pipeline safety. We believe that the Midstream Entities' pipeline operations are in substantial compliance with applicable PHMSA and state requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on the Midstream Entities' results of operations or financial positions.

Bayou Corne Sinkhole Incident. The Partnership owns and operates a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and our underground storage reservoirs located in Napoleonville, Louisiana.

Following the formation of the sinkhole, the Partnership and other pipeline operators in the area promptly undertook steps to depressurize and shut down their pipelines in the affected area. As a result of the sinkhole, it was necessary to permanently remove from service a section of its 36-inch diameter natural gas pipeline. The Partnerhsip worked with its customers to secure alternative natural gas supplies to minimize disruptions while a replacement pipeline was constructed. The replacement pipeline was completed and services resumed in May 2014. The Partnership also implemented additional inspection and operational measures at its nearby underground facility. The damage to the Partnership's business related to the sinkhole, including costs and loss of business, has been considerable.

The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine Company, LLC (“Texas Brine”), the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. The Partnership also filed a claim with its insurers, which its insurers denied. The Partnership disputed the denial and sued its insurers, but the Partnership has agreed to stay the matter pending resolution of its claims against Texas Brine and its insurers. In August 2014, the Partnership received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that the Partnership will be able to fully recover its losses through insurance recovery or claims against responsible parties. Please read “Item 3. Legal Proceedings.”

Office Facilities

The Midstream Entities occupy approximately 108,500 square feet of space at our executive offices in Dallas, Texas under a lease expiring in August 2019, approximately 25,100 square feet of office space for the Partnership’s Louisiana operations in Houston, Texas with lease terms expiring in April 2023 and approximately 9,000 square feet of office space in

Lafayette, Louisiana with lease terms expiring in January 2023. The Partnership also occupies approximately 12,500 square feet, 2,200 square feet and 4,700 square feet at Devon's Bridgeport, Oklahoma City and Cresson office buildings, respectively, under leases with a wholly-owned subsidiary of Devon which are scheduled to expire in March 2016.

In November 2014, the Partnership entered into a new agreement to lease approximately 157,600 square feet of space for its offices in Dallas, Texas with a lease term commencing in June 2016.

Employees

As of December 31, 2014, the Partnership (through its subsidiaries) employed approximately 1,148 full-time employees. Approximately 256 of the Partnership's employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. The Partnership is not party to any collective bargaining agreements and it has not had any significant labor disputes in the past. The Partnership believes that it has good relations with its employees.

Item 1A. Risk Factors

The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included herein.

Risks Related to the Company

Our cash flow consists almost exclusively of distributions from EnLink Midstream Partners, LP and EnLink Midstream Holdings, LP.

Currently, our only cash-generating assets are our partnership interests in EnLink Midstream Partners, LP and EnLink Midstream Holdings, LP. Our cash flow is therefore completely dependent upon the ability of the Partnership and Midstream Holdings to make distributions to their partners. Accordingly, you should read and consider the risk factors described under the caption "-Risks Inherent in the Midstream Entities' Business." The amount of cash that the Partnership and Midstream Holdings can distribute to their partners, including us, each quarter principally depends upon the amount of cash it generates from their operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in their gathering and transmission pipelines;
- the level of the Midstream Entities' processing operations;
- the fees the Midstream Entities charge and the margins they realizes for their services;
- the prices of, levels of production of and demand for crude oil, condensate, NGLs and natural gas;
- the volume of natural gas the Midstream Entities gather, compress, process, transport and sell, the volume of NGLs the Midstream Entities process or fractionate and sell, the volume of crude oil the Midstream Entities handle at their crude terminals, the volume of crude oil and condensate the Midstream Entities gather, transport, purchase and sell, the volumes of condensate stabilized and the volumes of brine the Partnership disposes;
- the relationship between natural gas and NGL prices; and
- the Midstream Entities' level of operating costs.

In addition, the actual amount of cash the Partnership and Midstream Holdings will have available for distribution will depend on other factors, some of which are beyond their control, including:

- the level of capital expenditures the Midstream Entities make;

- the cost of acquisitions, if any;
- the Partnership’s debt service requirements;
- fluctuations in their working capital needs;

- the Partnership’s ability to make working capital borrowings under its bank credit facility to pay distributions;
- prevailing economic conditions; and
- the amount of cash reserves established by their respective general partners in their sole discretion for the proper conduct of business.

Because of these factors, the Partnership and Midstream Holdings may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash the Partnership and Midstream Holdings have available for distribution depends primarily upon their cash flows, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership and Midstream Holdings may make cash distributions during periods when they record losses and may not make cash distributions during periods when it records net income.

Although we control the Partnership, the General Partner owes fiduciary duties to the Partnership and the unitholders. Conflicts of interest exist and may arise in the future as a result of the relationship between us and our affiliates, including the General Partner, on the one hand, and the Partnership and its limited partners, on the other hand. The directors and officers of EnLink Midstream GP, LLC have fiduciary duties to manage the General Partner in a manner beneficial to us, its owner. At the same time, the General Partner has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and its limited partners. The board of directors of EnLink Midstream GP, LLC will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to the Partnership and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and the Partnership, on the other hand;
- the determination of the amount of cash to be distributed to the Partnership’s partners and the amount of cash to be reserved for the future conduct of the Partnership’s business;
- the determination whether to make borrowings under the Partnership’s credit facility to pay distributions to partners; and
- any decision we make in the future to engage in activities in competition with the Partnership.

If the General Partner is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of the Partnership, its value, and therefore the value of our common units, could decline.

The General Partner may make expenditures on behalf of the Partnership for which it will seek reimbursement from the Partnership. In addition, under Delaware law, the General Partner, in its capacity as the General Partner of the Partnership, has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to the General Partner. To the extent the General Partner incurs obligations on behalf of the Partnership, it is entitled to be reimbursed or indemnified by the Partnership. In the event that the Partnership is unable or unwilling to reimburse or indemnify the General Partner, the General Partner may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of our common units.

If in the future we cease to manage and control the Partnership, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control the Partnership and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify our organizational structure or our contractual rights so as to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us and our affiliates, and adversely affect the price of our common units.

We are treated as a corporation subject to entity level federal and state income taxation. Any such entity level income taxes will reduce the amount of cash available for distribution to you.

We are treated as a corporation for tax purposes that is required to pay federal and state income tax on our taxable income at corporate rates. Historically, we have had net operating losses that eliminated substantially all of our taxable income and, thus, we historically have not had to pay material amounts of income taxes. We anticipate that taxable income during 2015 will be sufficient to fully utilize our remaining net operating loss carryforwards. As a result, we will likely incur material amounts of federal and state income tax liabilities on the taxable income we earn, which will reduce the cash available for distribution to our shareholders.

The terms of our credit facility may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

Our credit agreement contains, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. In addition, our credit facility requires us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under our credit facility. Upon the occurrence of such an event of default, all amounts outstanding under the credit facility could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If we are unable to repay the accelerated debt under our credit facility, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged the Partnership common units and the 100% membership interest in the General Partner that are indirectly held by us, along with our 100% equity interest in each of our wholly-owned subsidiaries and our limited partner interest in Midstream Holdings as collateral under our credit facility. If indebtedness under our credit facility is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in our credit facility and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Certain events of default under the Partnership’s credit facility, the occurrence of certain bankruptcy events affecting the Midstream Entities or our failure to continue to control the Partnership and Midstream Holdings could constitute an event of default under our credit facility.

Under the terms of our credit facility, certain events of default under the Partnership’s credit facility could constitute an event of default under our credit facility. Additionally, certain events of default under our credit facility relate specifically to events relating to the Midstream Entities, including certain bankruptcy events affecting the Midstream Entities or any event that causes us to no longer indirectly control the Partnership or Midstream Holdings. Additionally, any default by the Partnership under the terms of its credit facility could limit its ability to make distributions to us.

Risks Inherent in the Midstream Entities’ Business

Midstream Holdings is dependent on Devon for substantially all of the natural gas that it gathers, processes and transports. After the expiration of the five-year minimum volume commitments from Devon, a material decline in the volumes of natural gas that Midstream Holdings gathers, processes and transports for Devon could result in a material decline in the Midstream Entities’ operating results and cash available for distribution.

Midstream Holdings relies on Devon for a substantial portion of its natural gas supply. For the year ended December 31, 2014, Devon represented a 30.4% of our consolidated revenues. In order to minimize volumetric exposure, in March 2014 Midstream Holdings received five-year minimum volume commitments from Devon at the Bridgeport processing facility, Bridgeport and East Johnson County gathering systems and the Cana system. After the expiration of these five-year minimum volume commitments, a material decline in the volume of natural gas that Midstream Holdings gathers and transports on its systems would result in a material decline in our combined total operating revenues and cash flow. In addition, Devon may determine in the future that drilling activity in areas of operation other than Midstream Holdings' is strategically more attractive. A shift in Devon's focus away from Midstream Holdings' areas of operation could result in reduced throughput on Midstream Holdings' systems after the five-year minimum volume commitments expire and cause a material decline in our total operating revenues and cash flow.

Because the Midstream Entities are substantially dependent on Devon as their primary customer and through Devon's control of us and our control of the Partnership's general partner, any development that materially and adversely affects Devon's operations, financial condition or market reputation could have a material and adverse impact on the Midstream Entities and us. Material adverse changes at Devon could restrict our access to capital, make it more expensive to access the capital markets or increase the costs of our or the Partnership's borrowings.

The Midstream Entities are substantially dependent on Devon as their primary customer and through Devon's control of us and our control of the Partnership's general partner, and we expect the Midstream Entities to derive a substantial majority of their gross operating margin from Devon for the foreseeable future. As a result, any event, whether in the Midstream Entities' area of operations or otherwise, that adversely affects Devon's production, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect the Midstream Entities' revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Devon, some of which are the following:

- potential changes in the supply of and demand for oil, natural gas and natural gas liquids ("NGLs") and related products and services;
- risks relating to Devon's exploration and drilling programs, including potential environmental liabilities;
- adverse effects of governmental and environmental regulation; and
- general economic and financial market conditions.

Further, the Midstream Entities are subject to the risk of non-payment or non-performance by Devon, including with respect to Midstream Holdings' gathering and processing agreements. We cannot predict the extent to which Devon's business will be impacted by deteriorating pricing conditions in the energy industry, nor can we estimate the impact such conditions would have on Devon's ability to perform under Midstream Holdings' gathering and processing agreements. Additionally, due to our relationship with Devon, our or the Partnership's ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairments to Devon's financial condition or adverse changes in its credit ratings. Any material limitations on our or the Partnership's ability to access capital as a result of such adverse changes at Devon could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Devon could negatively impact our or the Partnership's unit price, limiting our ability to raise capital through equity issuances or debt financing or our ability to engage in, expand or pursue our business activities and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Please see Item 1.A in Devon's Annual Report on Form 10-K for the year ended December 31, 2014 for a full discussion of the risks associated with Devon's business.

Due to the Midstream Entities' lack of asset diversification, adverse developments in the Midstream Entities' gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would reduce their ability to make distributions to us.

The Midstream Entities rely exclusively on the revenues generated from their gathering, transmission, processing, fractionation, crude oil, natural gas, condensate and NGL services businesses and as a result their financial condition depends upon prices of, and continued demand for, natural gas, NGLs, condensate and crude oil. Due to the Midstream Entities' lack of asset diversification, an adverse development in one of these businesses may have a significant impact on the Midstream Entities' financial condition and their ability to make distributions to us.

A significant portion of the Midstream Entities' operations are located in the Barnett Shale, making the Midstream Entities vulnerable to risks associated with having revenue-producing operations concentrated in a limited number of geographic areas.

The Midstream Entities' revenue-producing operations are geographically concentrated in the Barnett Shale, causing them to be disproportionally exposed to risks associated with regional factors. Specifically, the Midstream Entities' operations in the Barnett Shale accounted for approximately 24.3% of their consolidated revenues for the period following the business combination, from March7, 2014 through December 31, 2014. The concentration of the Midstream Entities' operations in these regions also increases exposure to unexpected events that may occur in these regions such as natural disasters or labor difficulties. Any one of these events has the potential to have a relatively significant impact on the Midstream Entities operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on the Midstream Entities financial condition and results of operations.

The Midstream Entities must continually compete for crude oil, condensate and natural gas supplies, and any decrease in supplies of such commodities could adversely affect the Midstream Entities’ financial condition and results of operations.

In order to maintain or increase throughput levels in the Midstream Entities’ natural gas gathering systems and asset utilization rates at their processing plants and to fulfill their current sales commitments, the Midstream Entities must continually contract for new product supplies. The Midstream Entities may not be able to obtain additional contracts for crude oil, condensate, natural gas and NGL supplies. The primary factors affecting the Midstream Entities’ ability to connect new wells to their gathering facilities include the Midstream Entities’ success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near their gathering systems. If the Midstream Entities are unable to maintain or increase the volumes on their systems by accessing new supplies to offset the natural decline in reserves, the Midstream Entities' business and financial results could be materially, adversely affected. In addition, the Midstream Entities’ future growth will depend in part upon whether they can contract for additional supplies at a greater rate than the rate of natural decline in their current supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil, condensate and natural gas reserves. Continued periods of low commodity prices may put downward pressure on future drilling activity which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to the Midstream Entities’ systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying the Midstream Entities’ processing plants. The Midstream Entities have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in production or in the level of drilling activity in the Midstream Entities’ principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on the Midstream Entities’ results of operations and financial position.

Any decrease in the volumes that the Midstream Entities gather, process, fractionate or transport would adversely affect their financial condition, results of operations and cash flows.

The Midstream Entities’ financial performance depends to a large extent on the volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on their assets. Decreases in the volumes of natural gas, crude oil, condensate and NGLs we gather, process, fractionate or transport would directly and adversely affect the Midstream Entities’ revenues and results of operations. These volumes can be influenced by factors beyond the Midstream Entities’ control, including:

•environmental or other governmental regulations;

•weather conditions;

•increases in storage levels of natural gas and NGLs;

•increased use of alternative energy sources;

•decreased demand for natural gas and NGLs;

•fluctuations in commodity prices, including the prices of natural gas, NGLs, crude oil and condensate;

•economic conditions;

•supply disruptions;

•availability of supply connected to the Midstream Entities’ systems; and

- availability and adequacy of infrastructure to gather and process supply into and out of the Midstream Entities' systems.

The volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on the Midstream Entities' assets also depend on the production from the regions that supply its systems. Supply of natural gas, crude oil, condensate and NGLs can be affected by many of the factors listed above, including commodity prices and weather. In order to maintain or increase throughput levels on the Midstream Entities' systems, the Midstream Entities must obtain new sources of natural gas, crude oil, condensate and NGLs. The primary factors affecting the Midstream Entities' ability to obtain non-dedicated sources of natural gas, crude oil, condensate and NGLs include (i) the level of successful leasing, permitting and drilling activity in the Midstream Entities' areas of operation, (ii) the Midstream Entities' ability to compete for volumes from new wells and (iii) the Midstream Entities' ability to compete successfully for volumes from sources connected to other pipelines. The Midstream Entities have no control over the level of drilling activity in their areas of operation, the amount of reserves associated with wells connected to their systems or the rate at which production from a well declines. In addition, the Midstream Entities have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment.

The Midstream Entities' construction of new assets may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect the Midstream Entities' cash flows, results of operations and financial condition.

The construction of additions or modifications to the Midstream Entities' existing systems and the construction of new midstream assets involves numerous regulatory, environmental, political and legal uncertainties beyond their control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If the Midstream Entities undertake these projects, they may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, the Midstream Entities' revenues may not increase due to the successful construction of a particular project. For instance, if the Midstream Entities expand a pipeline or construct a new pipeline, the construction may occur over an extended period of time, and they may not receive any material increases in revenues promptly following completion of a project or at all. Moreover, the Midstream Entities may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve their expected investment return, which could adversely affect the Midstream Entities' results of operations and financial condition. In addition, the construction of additions to the Midstream Entities' existing gathering and processing assets will generally require them to obtain new rights-of-way and permits prior to constructing new pipelines or facilities. The Midstream Entities may be unable to timely obtain such rights-of-way or permits to connect new product supplies to their existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for the Midstream Entities to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, the Midstream Entities' cash flows could be adversely affected.

Construction of the Midstream Entities' major development projects subjects them to risks of construction delays, cost over-runs, limitations on their growth and negative effects on their operating results, liquidity and financial position.

The Midstream Entities are engaged in the planning and construction of several major development projects, some of which will take a number of months before commercial operation, such as the Partnership's ORV condensate pipeline project and its West Texas expansion project. These projects are complex and subject to a number of factors beyond the Midstream Entities' control, including delays from third-party landowners, the permitting process, complying with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on the Midstream Entities' business, financial condition, results of operations and liquidity. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed the Midstream Entities' estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed the Midstream Entities' estimates, their liquidity and capital position could be adversely affected. This level of development activity requires significant effort from the Midstream Entities' management and technical personnel and places additional requirements on their financial resources and internal financial controls. The Midstream Entities may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

The Midstream Entities typically do not regularly obtain independent evaluations of hydrocarbon reserves; therefore, volumes the Midstream Entities service in the future could be less than anticipated.

The Midstream Entities typically do not obtain independent evaluations on a regular basis of hydrocarbon reserves connected to their gathering systems or that they otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, the Midstream Entities do not have independent estimates of total reserves serviced by their assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than the Midstream Entities anticipate and they are unable to secure additional sources, then the volumes transported on the Midstream Entities' gathering systems or that they otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on the Midstream Entities' results of operations and financial condition.

The Midstream Entities may not be successful in balancing their purchases and sales.

The Midstream Entities are a party to certain long-term gas, NGL and condensate sales commitments that they satisfy through supplies purchased under long-term gas, NGL and condensate purchase agreements. When the Midstream Entities enter into those arrangements, their sales obligations generally match their purchase obligations. However, over time the supplies that the Midstream Entities have under contract may decline due to reduced drilling or other causes and the Midstream Entities may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause the Midstream Entities' purchases and sales not to be balanced. If the Midstream Entities' purchases and sales are not balanced, they will face increased exposure to commodity price risks and could have increased volatility in their operating income.

The Midstream Entities have made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect the Midstream Entities' margins or even result in losses. For example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. The Partnership buys gas for this contract on several different production-area indices on its NTPL and sell the gas into a different market area index. The Partnership realizes a loss on the delivery of gas under this contract each month based on current prices. The balance sheet as of December 31, 2014 reflects a liability of $80.7 million related to this performance obligation based on forecasted discounted cash obligations in excess of market under this gas delivery contract. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

The Midstream Entities' profitability is dependent upon prices and market demand for oil, condensate, natural gas and NGLs, which are beyond their control and have been volatile.

The Midstream Entities are subject to significant risks due to fluctuations in commodity prices. The Midstream Entities are directly exposed to these risks primarily in the gas processing and NGL fractionation components of their business. For the period following the business combination, from March 7, 2014 through December 31, 2014, approximately 1.68% of the Midstream Entities' total gross operating margin was generated under percent of liquids contracts. Under these contracts the Midstream Entities receive a fee in the form of a percentage of the liquids recovered and the producer bears all the cost of the natural gas shrink. Accordingly, the Midstream Entities' revenues under these contracts are directly impacted by the market price of NGLs.

The Midstream Entities also realize processing gross operating margins under processing margin contracts. For the period following the business combination, from March 7, 2014 through December 31, 2014, approximately 2.10% of the Partnership's total gross operating margin was generated under processing margin contracts. The Partnership has a number of processing margin contracts for activities at its Plaquemine and Pelican processing plants. Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and it makes a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction ("PTR"). The Partnership's margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices. Although the Partnership does not currently have any processing margin contracts for its Blue Water and Eunice plants, it does have the opportunity to process liquids from wet gas flowing on the pipelines connected to these plants, as well as its other processing plants, when market pricing is favorable. The Partnership's Eunice and Blue Water plants are not profitable to operate unless market pricing is very favorable.

Although the majority of the Midstream Entities' NGL fractionation business is under fee-based arrangements, a portion of their business is exposed to commodity price risk because they realize a margin due to product upgrades associated with their Cajun-Sibon fractionation business. For the period following the business combination from

March 7, 2014 through December 31, 2014, margins realized associated with product upgrades represented less than 1% of the Midstream Entities' gross operating margin.

The Midstream Entities are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of oil, condensate, natural gas and NGLs connected to or near their assets and on their margins for transportation between certain market centers. Low prices for these products will reduce the demand for the Midstream Entities’ services and volumes on their systems.

Although the majority of the Midstream Entities' NGL fractionation business is under fee-based arrangements, a portion of their business is exposed to commodity price risk because they realizes a margin due to product upgrades associated with their Cajun-Sibon fractionation business. For the period following the business combination from March 7, 2014 through December 31, 2014, margins realized associated with product upgrades represented less than 1% of the Midstream Entities' gross operating margin.

The prices of oil, condensate, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2014 ranged from a high of $107.26 per Bbl in June 2014 to a low of $53.27 per Bbl in December 2014. Weighted average NGL prices in 2014 (based on the Oil Price Information Service (“OPIS”) Napoleonville daily average spot liquids prices) ranged from a high of $1.27 per gallon in February 2014 to a low of $0.48 per gallon in December 2014. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2014 ranged from a high of $7.94 per MMBtu in March 2014 to a low of $2.75 per MMBtu in December 2014.

The markets and prices for oil, condensate, natural gas and NGLs depend upon factors beyond the Midstream Entities’ control. These factors include the supply and demand for oil, condensate, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil, condensate and natural gas production;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil, natural gas and NGLs;
- international demand for oil and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of “greenhouse gases.”

Changes in commodity prices also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil and condensate we gather and process and NGLs we fractionate. The volatility in commodity prices may cause the Midstream Entities’ gross operating margin and cash flows to vary widely from period to period. The Partnership’s hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the Midstream Entities’ throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in “Item 7A. Quantitative and Qualitative Disclosure about Market Risk.” The Partnership’s use of derivative financial instruments does not eliminate the Midstream Entities’ exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce the Partnership’s income.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather, process or transport do not meet the natural gas quality requirements of such pipelines or facilities, the Midstream Entities’ gross operating margin and cash flow could be adversely affected.

The Midstream Entities' gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties, including Atmos Energy, Enable Midstream Partners, ONEOK Partners and others. The continuing operation of, and the Midstream Entities' continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within the Midstream Entities' control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if the Midstream Entities' costs to access and transport on these third-party pipelines significantly increase, the Midstream Entities' profitability could be reduced. If any such increase in costs occurs, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes the Midstream Entities gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, the Midstream Entities' operating margin and cash flow could be adversely affected.

The Partnership's debt levels could limit our flexibility and adversely affect its financial health or limit its flexibility to obtain financing and to pursue other business opportunities.

The Partnership continues to have the ability to incur debt, subject to limitations in its credit facility. The Partnership's level of indebtedness could have important consequences to it, including the following:

- the Partnership's ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- the Partnership's funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of the Partnership's cash flows required to make interest payments on its debt;
- the Partnership's debt level will make it more vulnerable to general adverse economic and industry conditions; and
- limit the Partnership's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates.

In addition, the Partnership's ability to make scheduled payments or to refinance our obligations depends on its successful financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond the Partnership's control. If the Partnership's cash flow and capital resources are insufficient to fund its debt service obligations, the Partnership may be forced to take actions such as reducing distributions, reducing or delaying its business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing its debt or seeking additional equity capital. The Partnership may not be able to effect any of these actions on satisfactory terms or at all.

The Midstream Entities are vulnerable to operational, regulatory and other risks due to their concentration of assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

Midstream Holdings' operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because the Midstream Entities have a significant portion of their assets located in these two areas. The Midstream Entities' concentration of activity in Louisiana and the Gulf of Mexico makes the Midstream Entities more vulnerable than many of its competitors to the risks associated with these areas, including:

- adverse weather conditions, including hurricanes and tropical storms;
- delays or decreases in production, the availability of equipment, facilities or services; and
- changes in the regulatory environment.

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on the Midstream Entities' results of operations than they might have on other midstream companies that have operations in more diversified geographic areas.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect the Midstream Entities' results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons could result in a decline in the volume of NGL products the Midstream Entities handle or reduce the fees the Midstream Entities charge for their services. The

Midstream Entities' NGL products and the demand for these products are affected as follows:

- Ethane. Ethane is typically supplied as purity ethane or as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.

- Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for the Midstream Entities' propane may be reduced during periods of warmer-than-normal weather.

- Normal Butane. Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

- Isobutane. Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

- Natural Gasoline. Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect demand for the services the Midstream Entities provide as well as NGL prices, which would negatively impact the Midstream Entities' results of operations and financial condition.

The Midstream Entities expect to encounter significant competition in any new geographic areas into which they seek to expand, and the Midstream Entities' ability to enter such markets may be limited.

If the Midstream Entities expand their operations into new geographic areas, the Midstream Entities expect to encounter significant competition for natural gas, condensate, NGLs and crude oil supplies and markets. Competitors in these new markets will include companies larger than the Midstream Entities, which have both lower cost of capital and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, the Midstream Entities may not be able to successfully develop acquired assets and markets located in new geographic areas and their results of operations could be adversely affected.

The terms of the Partnership's credit facility and indentures may restrict its current and future operations, particularly its ability to respond to changes in business or to take certain actions.

The Partnership's credit agreement and the indentures governing its senior notes contain, and any future indebtedness the Partnership incurs will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on the Partnership's ability to engage in acts that may be in its best long-term interest. One or more of these agreements include covenants that, among other things, restrict the Partnership's ability to:

- incur subsidiary indebtedness;
- engage in transactions with its affiliates;
- consolidate, merge or sell substantially all of its assets;
- incur liens;

- enter into sale and lease back transactions; and
- change business activities the Partnership conduct.

In addition, the Partnership's credit facility requires it to satisfy and maintain a specified financial ratio. The Partnership's ability to meet that financial ratio can be affected by events beyond its control, and the Partnership cannot assure you that it will continue to meet that ratio.

A breach of any of these covenants could result in an event of default under the Partnership’s credit facility and indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If indebtedness under the Partnership’s credit facility or indentures is accelerated, there can be no assurance that it will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

The Midstream Entities do not own most of the land on which their pipelines and compression facilities are located, which could disrupt their operations.

The Midstream Entities do not own most of the land on which their pipelines and compression facilities are located, and they are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if they do not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. The Midstream Entities sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. The Midstream Entities’ loss of these rights, through their inability to renew right-of-way contracts, leases or otherwise, could cause them to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce their revenue.

The Midstream Entities offer pipeline, truck, rail and barge services. Significant delays, inclement weather or increased costs affecting these transportation methods could materially affect the Midstream Entities’ operations and earnings.

The Midstream Entities offer pipeline, truck, rail and barge services. The costs of conducting these services could be negatively affected by factors outside of the Midstream Entities’ control, including rail service interruptions, new laws and regulations, rate increases, tariffs, rising fuel costs or capacity constraints. Inclement weather, including hurricanes, tornadoes, snow, ice and other weather events, can negatively impact the Midstream Entities’ distribution network. In addition, rail, truck or barge accidents involving the transportation of hazardous materials could result in significant claims arising from personal injury, property damage and environmental penalties and remediation.

The Midstream Entities could experience increased severity or frequency of trucking accidents and other claims.

Potential liability associated with accidents in the trucking industry is severe and occurrences are unpredictable. A material increase in the frequency or severity of accidents or workers’ compensation claims or the unfavorable development of existing claims could be expected to materially adversely affect the Midstream Entities’ results of operations. In the event that accidents occur, the Midstream Entities may be unable to obtain desired contractual indemnities, and their insurance may be inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses.

Changes in trucking regulations may increase the Midstream Entities’ costs and negatively impact their results of operations.

The Midstream Entities’ trucking services are subject to regulation as a motor carrier by the United States Department of Transportation (“DOT”) and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over the Midstream Entities’ trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact the Midstream Entities’ operations and affect the economics of the industry by requiring changes in operating practices or by changing the demand for or the cost of providing trucking services. Some of these possible changes include increasingly stringent fuel emission limits, changes in the regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements.

If the Midstream Entities do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with their asset base, their future growth will be limited.
The Midstream Entities' ability to grow depends, in part, on their ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If the Midstream Entities are unable to make accretive acquisitions either because they are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or at all or (3) outbid by competitors, then their future growth and ability to increase distributions will be limited.

From time to time, the Midstream Entities may evaluate and seek to acquire assets or businesses that they believe complement their existing business and related assets. The Midstream Entities may acquire assets or businesses that they plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in the Midstream Entities' indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect the Midstream Entities' operations and cash flows. If the Midstream Entities consummate any future acquisition, their capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that the Midstream Entities will consider in determining the application of these funds and other resources.

The Midstream Entities may not be able to retain existing customers or acquire new customers, which would reduce their revenues and limit their future profitability.

The renewal or replacement of existing contracts with the Midstream Entities' customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond the Midstream Entities' control, including competition from other midstream service providers, and the price of, and demand for, crude oil, condensate, NGLs and natural gas in the markets they serve. The inability of the Midstream Entities' management to renew or replace their current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on the Midstream Entities' profitability.

In particular, the Midstream Entities' ability to renew or replace their existing contracts with industrial end-users and utilities impacts our profitability. For the period following the business combination, from March 7, 2014 through December 31, 2014, approximately 59.5% of the Midstream Entities' sales of gas that was transported using the Midstream Entities' physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities may be reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with the Midstream Entities in the marketing of natural gas, the Midstream Entities often compete in the end-user and utilities markets primarily on the basis of price.

The Midstream Entities are exposed to the credit risk of their customers and counterparties, and a general increase in the nonpayment and nonperformance by their customers could have an adverse effect on their financial condition and results of operations.

Risks of nonpayment and nonperformance by the Midstream Entities' customers are a major concern in their business. The Midstream Entities are subject to risks of loss resulting from nonpayment or nonperformance by their customers and other counterparties, such as their lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by the Midstream Entities' customers could adversely affect their results of operations and reduce their ability to make distributions to us.

Increased federal, state and local legislation and regulatory initiatives, as well as government reviews, relating to hydraulic fracturing could result in increased costs and reductions or delays in natural gas production by the Midstream Entities' customers, which could adversely impact their revenues.

A portion of the Midstream Entities' suppliers' and customers' natural gas production is developed from unconventional sources, such as deep gas 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. Hydraulic fracturing activities are generally regulated by state oil and gas commissions; however, the Environmental Protection Agency (the "EPA") has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where the EPA is the permitting authority. In addition, legislation has been proposed, but not yet passed that would provide for federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic-fracturing process. State legislatures and agencies are also enacting legislation and promulgating rules to regulate hydraulic fracturing and require disclosure of hydraulic fracturing chemicals. In January 2013, the Bureau of Land Management of the U.S. Department of the Interior published for public comment a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands with respect to which the Department of Interior is expected to promulgate a final rule sometime in 2015.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On April 13, 2012, President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. The EPA has also issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration. In addition to the EPA, other federal agencies are analyzing, or have been requested to review, a variety of issues, environmental and otherwise, associated with hydraulic fracturing. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms.

Moreover, some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including temporary or permanent bans, additional permit requirements, operational restrictions and chemical disclosure obligations on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas. For example, Oklahoma, Texas, and many other states have imposed regulations regarding disclosure of information regarding chemicals in well stimulation operations. State and federal regulatory agencies also have recently focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily, and some state regulatory agencies have modified their regulations to account for induced seismicity. For example, the TRRC rules allow the TRRC to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. The Oklahoma Corporation Commission has also taken steps to focus on induced seismicity, including increasing the frequency of required recordkeeping for wells that dispose into certain formations and considering seismic information in permitting decisions. As regulatory agencies continue to study induced seismicity, such agencies may promulgate additional regulations affecting the Midstream Entities' brine disposal operations.

We cannot predict whether any additional legislation or regulations will be enacted and, if so, what the provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions for

the Midstream Entities' suppliers and customers that could reduce the volumes of natural gas that move through the Midstream Entities' gathering systems which could materially adversely affect their revenue and results of operations.
Transportation on certain of the Midstream Entities' natural gas pipelines is subject to federal and state rate and service regulation, which could limit the revenues the Midstream Entities collect from their customers and adversely affect the cash available for distribution to us. The imposition of regulation on the Midstream Entities' currently unregulated natural gas pipelines also could increase their operating costs and adversely affect the cash available for distribution to us.

The rates, terms and conditions of service under which the Midstream Entities transport natural gas in their pipeline systems in interstate commerce are subject to regulation of the FERC under the NGA and under Section 311 of the Natural Gas

Policy Act and the rules and regulations promulgated under those statutes. Under the NGA, FERC regulation requires that interstate natural gas pipeline rates be filed with the FERC and that these rates be “just and reasonable” and not unduly discriminatory, although negotiated or settlement rates may be accepted in certain circumstances. Interested persons may challenge proposed new or changed rates, and the FERC is authorized to suspend the effectiveness of such rates pending an investigation or hearing. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a pipeline to change its rates prospectively. Accordingly, action by the FERC could adversely affect the Midstream Entities' ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against the Midstream Entities could have a material adverse effect on their business, financial condition, results of operations, and cash available for distribution. Under the NGPA, the Midstream Entities are required to justify their rates for interstate transportation service on a cost-of-service basis every five years. The Midstream Entities’ intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should the FERC or any of these state agencies determine that the Midstream Entities’ rates for Section 311 transportation service or intrastate transportation service should be lowered, the Midstream Entities’ business could be adversely affected.
The Midstream Entities’ natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, so the classification and regulation of the Midstream Entities’ gathering facilities are subject to change based on future determinations by the FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since the FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. The Midstream Entities’ gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on the Midstream Entities’ operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.
If the Midstream Entities fail to comply with all applicable the FERC-administered statutes, rules, regulations and orders, they could be subject to substantial penalties and fines. Under the EPAct 2005, the FERC has civil penalty authority to impose penalties for current violations of the NGA or NGPA of up to $1.0 million per day for each violation. The FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.
Other state and local regulations also affect the Midstream Entities’ business. The Midstream Entities are subject to some ratable take and common purchaser statutes in the states where they operate. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting the Midstream Entities’ rights as owners of gathering facilities to decide with whom the Midstream Entities contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which the Midstream Entities operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.
Transportation on the Partnership’s liquids pipelines is subject to federal rate and service regulation, which could limit the revenues the Partnership collects from its customers and adversely affect the cash available for distribution to us.
The Partnership’s liquids transportation pipelines in the ORV and the Cajun-Sibon NGL pipeline, which went into service in November 2013, are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates and terms and conditions of service for interstate service on liquids pipelines be just, reasonable and not unduly discriminatory or preferential. The ICA also requires that such rates and terms and conditions be set forth in tariffs filed with FERC. The ICA permits interested persons to challenge proposed new or changed rates and authorizes

FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rates are unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rates during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit the Partnership's ability to set rates based on its costs or could order the Partnership to reduce its rates and could require the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change the Partnership's terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As the Midstream Entities acquire, construct and operate new liquids assets and expand our liquids transportation business, the classification and regulation of their liquids transportation services are subject to ongoing assessment and change based on the services they provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC, which could increase the Midstream Entities' operating costs, decrease their rates and adversely affect their business.

The Midstream Entities may incur significant costs and liabilities resulting from compliance with pipeline safety regulations.

The states in which the Midstream Entities conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968. These standards only apply to certain natural gas gathering lines based on the gathering line's operating pressure and proximity to people. Because of their pressure and location, substantial portions of the Midstream Entities' gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be revised in the future and place more of the Midstream Entities' gathering facilities under jurisdiction of the DOT. Nonetheless, the Midstream Entities' natural gas transmission pipelines are subject to regulation by the DOT. In response to pipeline accidents in other parts of the country, Congress and the DOT, through PHMSA, have passed or are considering heightened pipeline safety requirements that may be applicable to gathering lines. As a result, the Midstream Entities' pipeline facilities are subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

At the state level, several states have passed legislation or promulgated rulemaking addressing pipeline safety. Compliance with pipeline integrity and other pipeline safety regulations issued by DOT or those issued by the TRRC could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. The Midstream Entities' costs relating to compliance with the required testing under the TRRC regulations were approximately at $2.5 million, $7.0 million, and $8.6 million for the years ended December 31, 2014, 2013 and 2012, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $1.8 million during 2015. If the Midstream Entities' pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then they may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced maximum allowable operating pressure, the cost of which cannot be estimated at this time.

In addition, the Midstream Entities' liquids transportation pipelines are subject to regulation by the DOT, through the PHMSA, pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended by the Pipeline Safety Improvement Act of 2002, and reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. PHMSA has adopted regulations requiring hazardous liquid pipeline operators to develop and implement integrity management programs for pipeline segments that, in the event of a leak or rupture, could affect "high consequence areas," such as high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. As the Midstream Entities' operations continue to expand into and around urban or more populated areas, such as the Barnett Shale, the Midstream Entities may incur additional expenses to mitigate noise, odor and light that may be emitted in their operations and expenses related to the appearance of their facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of Midstream Entities' facilities, imposing limitations on the noise levels of their facilities and requiring certain other improvements that increase the cost of our facilities. The Midstream Entities are also subject to claims by neighboring landowners for nuisance related to the construction and operation of Midstream Entities' facilities, which could subject them to damages for declines in neighboring property values due to their construction and operation of facilities.

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause the Midstream Entities to incur significant costs

and liabilities.
Many of the operations and activities of our gathering systems, processing plants, fractionators, brine disposal operations and other facilities are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from the Midstream Entities' facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by the Midstream Entities or locations to which they have sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines,

injunctions or both. Strict, joint and several liability may be incurred under these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties near the Midstream Entities' facilities or upon or through which their gathering systems traverse, 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 for releases of contaminants or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in the Midstream Entities' business due to their handling of natural gas, crude oil and other petroleum substances, the Partnership's brine disposal operations, air emissions related to the Midstream Entities' operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. For example, the Partnership operates brine disposal wells in Ohio and West Virginia and may gather brine from surrounding states. These wells are regulated under the federal Safe Drinking Water Act as Class II wells and under state laws. State laws and regulations that govern these operations can be more stringent than the Safe Drinking Water Act, such as the Ohio Department of Natural Resources rules which took effect October 1, 2012. These rules imposed new, more stringent environmentally responsible standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state of the art technology. They apply to new disposal wells and, as applicable, to existing wells. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. The Midstream Entities may incur material environmental costs and liabilities. Furthermore, the Midstream Entities' insurance may not provide sufficient coverage in the event an environmental claim is made against them.

In addition, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on the Partnership's brine disposal operations.

The Midstream Entities' business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect the Midstream Entities' products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect the Midstream Entities' profitability. Changes in laws or regulations could also limit the Midstream Entities' production or the operation of their assets or adversely affect the Midstream Entities' ability to comply with applicable legal requirements or the demand for crude oil, brine disposal services or natural gas, which could adversely affect the Midstream Entities' business and profitability.

Recently finalized rules under the Clean Air Act imposing more stringent requirements on the oil and gas industry could cause the Midstream Entities and their customers to incur increased capital expenditures and operating costs as well as reduce the demand for the Midstream Entities' services.

On April 17, 2012, the EPA issued final rules under the Clean Air Act that became effective on October 15, 2012. Among other things, these rules require additional emissions controls for natural gas and NGLs production, including New Source Performance Standards to address emissions of sulfur dioxide and VOCs and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require a number of modifications to our operations and our natural gas exploration and production suppliers' and customers' operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by the Midstream Entities' suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for the Midstream Entities' services. The rules are subject to an ongoing legal challenge brought by various parties, including environmental groups and industry, and the EPA has revised some aspects of the rules. Any further revisions could affect the Midstream Entities' operations, as well as the operations of their suppliers and customers.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services the Midstream Entities provide.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allowed the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. Since 2011, the EPA has required stationary sources that emit GHGs above regulatory and statutory thresholds to obtain a Prevention of Significant Deterioration permit. Moreover, on October 30, 2009, the EPA published a "Mandatory Reporting of Greenhouse Gases" final rule that established a comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. The Mandatory Reporting Rule was expanded by a rule promulgated on November 30, 2010 to include owners and operators of onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Reporting emissions from such onshore activities is required on an annual basis. The first reports were due in 2012 for emissions occurring in 2011. Additionally, the EPA has proposed to regulate greenhouse gas emissions from certain electric generating units under the Clean Air Act's New Source Performance Standards ("NSPS") program. The EPA may propose to regulate additional source categories under the NSPS program in the future.

On January 14, 2015, the Obama administration announced that the EPA will propose a rule in the summer of 2015 to set standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector, including transmission. A final rule is expected in 2016. The Administration's announcement also stated that other federal agencies, including the Bureau of Land Management, the PHMSA, and the Department of Energy will impose new or more stringent regulations on the oil and gas sector that will have the effect of reducing methane emissions

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, the Midstream Entities' equipment and operations could require the Midstream Entities to incur additional costs to reduce emissions of GHGs associated with their operations, could adversely affect their performance of operations in the absence of any permits that may be required to regulate emission of GHGs or could adversely affect demand for the natural gas the Midstream Entities gather, process or otherwise handle in connection with their services.

The Endangered Species Act and Migratory Bird Treaty Act govern our operations and additional restrictions may be imposed in the future, which could have an adverse impact on our operations.

The ESA and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the MBTA. The U.S. Fish and Wildlife Service and state agencies may designate critical or suitable habitat areas that they believe are necessary for the survival of threatened or endangered species. Such a designation could materially restrict use of or access to federal, state and private lands. Some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds. In these areas, the Midstream Entities may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and they may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when their operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to the Midstream Entities' activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. In addition, the U.S. Fish and Wildlife Service and state agencies regularly review species that are listing candidates, and designations of additional endangered or threatened species, or critical or suitable habitat, under the ESA could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

The Midstream Entities’ business involves many hazards and operational risks, some of which may not be fully covered by insurance.

The Midstream Entities’ operations are subject to the many hazards inherent in the gathering, compressing, processing, transporting, fractionating, disposing and storage of natural gas, NGLs, condensate, crude oil and brine, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs, crude oil, condensate and other hydrocarbons;

- induced seismicity;

- rail accidents, barge accidents and truck accidents; and

- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of the Midstream Entities' related operations. The Midstream Entities are not fully insured against all risks incident to their business. In accordance with typical industry practice, the Midstream Entities do not have business interruption insurance or any property insurance on any of their underground pipeline systems that would cover damage to the pipelines. The Midstream Entities are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect the Midstream Entities' operations and financial condition.

The adoption of derivatives legislation by the United States Congress and promulgation of related regulations could have an adverse effect on our ability to hedge risks associated with the Midstream Entities' business.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Midstream Entities encounter, reduce the Partnership's ability to monetize or restructure the Partnership's existing derivative contracts, and increase the Midstream Entities' exposure to less creditworthy counterparties. If the Partnership reduces its use of derivatives as a result of the legislation and regulations, the Partnership's results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect the Partnership's ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. The Partnership's revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on the Midstream Entities, their financial condition and their results of operations.

The Partnership's use of derivative financial instruments does not eliminate its exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce its income.

The Partnership's operations expose us to fluctuations in commodity prices, and the Partnership's credit facility exposes it to fluctuations in interest rates. The Partnership uses over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce the Partnership's exposure to short-term volatility in commodity prices. As of December 31, 2014, the Partnership had hedged only portions of its expected exposures to commodity price risk. In addition, to the extent the Partnership hedges it commodity price risk using swap instruments, the Partnership will forego the benefits of favorable changes in commodity prices. Although the Partnership does not currently have any financial instruments to eliminate its exposure to interest rate fluctuations, we may use financial instruments in the future to offset its exposure to interest rate fluctuations.

Even though monitored by management, the Partnership's hedging activities may fail to protect it and could reduce its earnings and cash flow. The Partnership's hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;

- the Partnership's counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and

- available hedges may not correspond directly with the risks against which the Partnership seeks protection. For example:

- the duration of a hedge may not match the duration of the risk against which the Partnership seeks protection;

- variations in the index the Partnership uses to price a commodity hedge may not adequately correlate with variations in the index the Partnership uses to sell the physical commodity (known as basis risk); and

- the Partnership may not produce or process sufficient volumes to cover swap arrangements the Partnership enters into for a given period. If the Partnership's actual volumes are lower than the volumes the Partnership estimated when entering into a swap for the period, it might be forced to satisfy all or a portion of its derivative obligation without the benefit of cash flow from the sale or purchase of the underlying physical commodity, which could adversely affect the Partnership's liquidity.

A failure in our computer systems or a cyber-attack on us, or third parties with whom we have a relationship, may adversely affect our ability to operate our business.

We are reliant on technology to conduct our businesses. Our business is dependent upon our operational and financial computer systems to process the data necessary to conduct almost all aspects of our business, including operating our pipelines, truck fleet and storage facilities, recording and reporting commercial and financial transactions and receiving and making payments. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business. Unknown entities or groups have mounted so-called "cyber-attacks" on businesses to disable or disrupt computer systems, disrupt operations and steal funds or data. Any such cyber-attack that affects us or our customers, suppliers or others with whom we do business, could have a material adverse effect on our business, cause us to incur a material financial loss and/or damage our reputation.

Subsidence and coastal erosion could damage the Partnership's pipelines along the Gulf Coast and offshore and the facilities of its customers, which could adversely affect its operations and financial condition.

The Partnership's pipeline operations along the Gulf Coast and offshore could be impacted by subsidence and coastal erosion. Such processes could cause serious damage to the Partnership's pipelines, which could affect its ability to provide transportation services. Additionally, such processes could impact the Partnership's customers who operate along the Gulf Coast, and they may be unable to utilize the Partnership's services. Subsidence and coastal erosion could also expose the Partnership's operations to increased risks associated with severe weather conditions, such as hurricanes, flooding and rising sea levels. As a result, the Partnership may incur significant costs to repair and preserve its pipeline infrastructure. Such costs could adversely affect our business, financial condition, results of operation or cash flows.

The Partnership's assets were constructed over many decades which may cause its 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 the Partnership's pipelines that could have a material adverse effect on its business and results of operations.

The Partnership's pipelines were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have varied 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 the Partnership's results of operations, financial position or cash flows, as well as its ability to make cash distributions to its unitholders.

The Midstream Entities' success depends on key members of their management, the loss or replacement of whom could disrupt their business operations.

The Midstream Entities depend on the continued employment and performance of the officers of the General Partner and key operational personnel. The Partnership's General Partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, the Midstream Entities' business operations could be materially adversely affected. The Midstream Entities do not maintain any "key man" life insurance for any officers.

Item 1B. Unresolved Staff Comments

We do not have any unresolved staff comments.

Item 2. Properties

A description of our properties is contained in "Item 1. Business."

Title to Properties

Substantially all of the Midstream Entities’ pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. The Midstream Entities have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which the Midstream Entities' pipelines were built was purchased in fee. The Midstream Entities' processing plants are located on land that the Midstream Entities lease or own in fee.

We believe that the Midstream Entities have satisfactory title to all of their rights-of-way and land assets. Title to these assets may be subject to encumbrances or defects. The Midstream Entities believe that none of such encumbrances or defects should materially detract from the value of their assets or from their interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. Legal Proceedings

Our operations and those of the Midstream Entities are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we or the Midstream Entities may be a defendant in various legal proceedings and litigation arising in the ordinary course of business, including litigation on disputes related to contracts, property use or damage and personal injury. Additionally, as the Midstream Entities continue to expand operations into more urban, populated areas, such as the Barnett Shale, they may see an increase in claims brought by area landowners, such as nuisance claims and other claims based on property rights. Except as otherwise set forth herein, we do not believe that any pending or threatened claim or dispute is material to our financial results on our operations. We maintain insurance policies with insurers in amounts and with coverage and deductibles as our general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

At times, the Partnership's gas-utility and common carrier subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain. As a result, the Partnership (or its subsidiaries) are party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value, if any, of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on the Partnership's consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to the United States District Court for the Eastern District of Louisiana. The amount of damages is unspecified. The Partnership's subsidiary, EnLink LIG, LLC, is one of the named defendants as the owner of pipelines in the area. On February 13, 2015, the court granted defendants' joint motion to dismiss and dismissed the plaintiff's claims with prejudice. The court's ruling is subject to appeal. The Partnership intends to vigorously defend the case. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable.

The Partnership owns and operates a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. The Partnership also filed a claim with its insurers, which its insurers denied its claim. The Partnership disputed the denial and sued its insurers, but the Partnership has agreed to stay the matter pending resolution of its claims against Texas Brine and its insurers. In August 2014, The Partnership received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. The Partnership cannot give assurance that it will be able to fully recover its losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added a subsidiary of the Partnership, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine, Occidental Chemical Corporation, and Vulcan Materials Company relating to claims arising from the Bayou Corne sinkhole. The suit is pending in the 23rd Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants have been pending since October 2012, plaintiffs are now alleging that EnLink Processing Services, LLC’s negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case. The Partnership has also filed a claim for defense and indemnity with its insurers.

In October 2014, Williams Olefins, L.L.C. filed a lawsuit against a subsidiary of the Partnership, EnLink NGL Marketing, LP, in the District Court of Tulsa County, Oklahoma. The plaintiff alleges breach of contract and negligent misrepresentation relating to an ethane output contract between the parties and the subsidiary’s termination of ethane production from one of its fractionation plants. The amount of damages is unspecified. The plaintiff also seeks specific performance under the contract. The validity of the causes of action, as well as the Partnership’s costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common units are listed on the NYSE under the symbol “ENLC”. Our common units began trading on March 10, 2014. There was no established public market for our common units prior to March 10, 2014. On February 11, 2015, there were approximately 41,953 record holders and beneficial owners (held in street name) of our common units. For equity compensation plan information, see discussion under “Item. 12 Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Equity Compensation Plan Information.”

The following table shows (i) the high and low closing sales prices per common unit, as reported by the NYSE and (ii) the amount of our quarterly distributions for the periods indicated.

	Range		Cash Distribution
	High	Low	Declared Per Unit
2014:			
Quarter Ended December 31	$40.86	$30.20	$0.235
Quarter Ended September 30	41.70	36.90	0.230
Quarter Ended June 30	42.18	33.63	0.220
Quarter Ended March 31	36.70	33.34	0.180

We intend to pay distributions to our unitholders on a quarterly basis equal to the cash we receive, if any, from distributions from the Partnership and Midstream Holdings less reserves for expenses, future distributions and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner’s then-current general partner interest, to the extent the board of directors of the General Partner exercises its option to do so; and
- cash reserves our board of directors believes are prudent to maintain.

Our ability to pay distributions is limited by the Delaware Limited Liability Company Act, which provides that a limited liability company may not pay distributions if, after giving effect to the distribution, the company’s liabilities would exceed the fair value of its assets. While our ownership of equity interests in the General Partner, the Partnership and Midstream Holdings are included in our calculation of net assets, the value of these assets may decline to a level where our liabilities would exceed the fair value of our assets if we were to pay distributions, thus prohibiting us from paying distributions under Delaware law.

During 2014, the Partnership paid quarterly distributions to its common unitholders in May, August and November of \$0.36, \$0.365 and \$0.37 related to the first, second and third quarters of 2014, respectively. The Partnership paid a quarterly distribution of $0.375 in February 2015 related to the fourth quarter of 2014. Our share of the distributions with respect to our limited and general partner interests in the Partnership totaled $45.2 million for the year ended December 31, 2014.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common units, the Standard & Poor's 500 Stock Index and a peer group of publicly traded partners of publicly traded limited partnerships in the Midstream natural gas, natural gas liquids, propane, and pipeline industries from March 10, 2014 through December 31, 2014. The chart assumes that $100 was invested on March 10, 2014, with distributions reinvested. The peer group includes MarkWest Energy Partners, L.P., Transfer Equity, L.P., Plains GP Holdings, L.P., Targa Resources, Inc. and Western Gas Equity Partners, L.P.

Item 6. Selected Financial Data

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of Predecessor, the predecessor to Midstream Holdings, which is the historical predecessor of ENLC and (2) for periods on or after March 7, 2014, the results of operations of ENLC, after giving effect to the business combination discussed under “Devon Energy Transaction” below. The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon prior to the business combination, including its 38.75% economic interest in GCF. However, in connection with the business combination, only the Predecessor’s systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% economic interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

The following table presents the selected historical financial and operating data of EnLink Midstream LLC and EnLink Midstream Holdings, LP Predecessor (the “Predecessor”), whose assets comprise the Midstream business, for the periods indicated. The selected combined historical financial data of the Predecessor are derived from the historical combined financial statements of the Predecessor and should be read together with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” below and its audited combined financial statements for the year ended December 31, 2014. The following information is only a summary and is not necessarily indicative of the results or future operations of the Company.

	Enlink Midstream , LLC				
	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions, except per unit data)				
Statement of Operations Data:					
Revenues:					
Revenues	$2,412.7	$179.4	$153.9	$13.6	$10.9
Revenues- affiliates	1,065.6	2,116.5	1,753.9	2,514.4	1,907.9
Gain on derivatives	22.1	—	—	—	—
Total revenue	3,500.4	2,295.9	1,907.8	2,528.0	1,918.8
Operating costs and expenses:					
Purchased gas, NGLs, condensate and crude oil	2,494.5	1,736.3	1,428.1	1,974.9	1,436.1
Operating expenses	278.2	156.2	149.9	137.1	105.8
General and administrative	97.3	45.1	41.7	38.5	37.6
Depreciation and amortization	280.3	187.0	145.4	133.5	112.2
Gain on sale of property	(0.1)	—	—	—	—
Impairments	—	—	16.4	—	—
Gain on litigation settlement	(6.1)	—	—	—	—
Other expenses	—	—	—	(58.1)	0.2
Total operating costs and expenses	3,144.1	2,124.6	1,781.5	2,225.9	1,691.9
Operating income	356.3	171.3	126.3	302.1	226.9
Other income (expense):					
Interest expense, net of interest income	(49.8)	—	—	—	—
Income from equity investments	18.9	14.8	2.0	9.3	5.1
Gain on extinguishment of debt	3.2	—	—	—	—
Other income (expense)	(0.5)	—	—	—	—
Total other income (expense)	(28.2)	14.8	2.0	9.3	5.1
Income from continuing operations before non-controlling interest and income taxes	328.1	186.1	128.3	311.4	232.0
Income tax provision	(76.4)	(67.0)	(46.2)	(112.1)	(83.5)
Net income from continuing operations	251.7	119.1	82.1	199.3	148.5
Discontinued operations:					
Income (loss) from discontinued operations, net of tax	1.0	(2.3)	(5.2)	18.9	34.8
Income from discontinued operations attributable to non-controlling interest, net of tax	—	(1.3)	(1.1)	(2.1)	(4.6)
Discontinued operations, net of tax	1.0	(3.6)	(6.3)	16.8	30.2
Net income	252.7	115.5	75.8	216.1	178.7
Less: Net income from continuing operations attributable to the non-controlling interest	126.7	—	—	—	—
Net income attributable to EnLink Midstream LLC	$126.0	$115.5	$75.8	$216.1	$178.7
Predecessor interest in net income	$35.5	$—	$—	$—	$—
EnLink Midstream LLC interest in net income	$90.5	$—	$—	$—	$—
Net income attributable to EnLink Midstream LLC per common unit:					
Basic and diluted common unit	$0.55	$—	$—	$—	$—
Distributions declared per common unit	$0.865	$—	$—	$—	$—

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	EnLink Midstream , LLC				
	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions, except per unit data)				
Balance Sheet Data (end of period):					
Property and equipment, net	$4,934.3	$1,768.1	$1,739.4	$1,550.7	$1,439.0
Total assets	$10,097.3	$2,309.8	$2,535.2	$2,305.3	$2,195.9
Long-term debt (including current maturities)	$2,022.5	$—	$—	$—	$—
Members' equity including non-controlling interest	$6,971.1	$—	$2,002.0	$1,901.2	$1,849.0

Non-GAAP Financial Measures

Cash Available for Distribution

We define cash available for distribution as distributions due to us from the Partnership and our interest in Midstream Holdings adjusted EBITDA (as defined herein), less maintenance capital, our specific general and administrative costs as a separate public reporting entity, the interest costs associated with our debt and current taxes attributable to our earnings. During 2014, we utilized federal net operating loss carryforwards totaling $98.1 million to offset our taxable income generated during 2014. We have $48.2 million of federal net operating loss carryforwards remaining as of December 31, 2014. We anticipate that taxable income during 2015 will be sufficient to utilize our remaining net operating loss carryforwards and that we will begin paying federal income taxes on our taxable income. Cash available for distribution is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Cash available for distribution is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment.

The GAAP measure most directly comparable to cash available for distribution is net income. Cash available for distribution should not be considered as an alternative to GAAP net income. Cash available for distribution is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Because cash available for distribution excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of cash available for distribution may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following is a calculation of the Company's cash available for distribution (in millions):

	Year Ended December 31, 2014	
Distribution declared by ENLK associated with (1):		
General partner interest	$2.2	
Incentive distribution rights	22.6	
ENLK common units owned	24.8	
Total share of ENLK distributions declared	$49.6	
Adjusted EBITDA of Midstream Holdings (2)	187.9	
Total cash available	$237.5	
Uses of cash:		
General and administrative expenses	(3.2	)
Current income taxes (3)	(3.5	)
Interest expense	(2.2	)
Maintenance capital expenditures (4)	(11.0	)
Total cash used	$(19.9	)
ENLC Cash Available for distribution	$217.6	

(1) Represents quarterly distributions paid by ENLK on May 14, 2014, August 13, 2014, November 13, 2014 and declared by ENLK and to be paid to ENLC on February 12, 2015.

(2) Represents ENLC's 50% interest in Midstream Holdings' adjusted EBITDA , which is disbursed on a monthly basis to ENLC by Midstream Holdings. Midstream Holdings' adjusted EBITDA is defined as earnings (excluding Predecessor earnings) plus depreciation, provision for income taxes and distributions from equity investment less income from equity investment. ENLC's share of Midstream Holdings' adjusted EBITDA is comprised of its 50% share in Midstream Holdings' net income of $131.6 million (excluding Predecessor earnings) plus its 50% share in Midstream Holdings' depreciation of $56.9 million, taxes of $1.0 million and distributions from equity investment of $5.5 million, less its 50% share of income from equity investment of $7.0 million.
(3) Represents ENLC’s stand-alone current tax expense. ENLC’s taxable income for 2014 did not exceed its federal net operating loss carryforward therefore its current tax expense for 2014 primarily represents current state income taxes.
(4) Represents ENLC's interest in Midstream Holdings' maintenance capital expenditures which is netted against the monthly disbursement of Midstream Holdings' adjusted EBITDA per (2) above.
The following table provides a reconciliation of ENLC net income from continuing operations to ENLC cash available for distribution (in millions):

	Year ended December 31, 2014	
Net income from continuing operations of ENLC	$251.7	
Less: Net income attributable to ENLK	(181.1	)
Net income of ENLC excluding ENLK	$70.6	
ENLC's share of distributions from ENLK (1)	49.6	
ENLC's interest in Midstream Holdings' depreciation (2)	56.9	
ENLC's interest in distributions from Midstream Holding's equity investment	5.5	
ENLC's interest in income from Midstream Holding's equity investment	(7.0	)
ENLC deferred income tax expense (3)	52.1	
Maintenance capital expenditures (4)	(11.0	)
Other items (5)	0.9	
ENLC cash available for distribution	$217.6	

(1) Represents quarterly distributions paid by ENLK on May 14, 2014, August 13, 2014, November 13, 2014 and declared by ENLK and to be paid to ENLC on February 12, 2015.
(2) Represents ENLC's interest in Midstream Holdings' depreciation, which is reflected as a non-cash deduction in the net income of ENLC excluding ENLK.
(3) Represents ENLC's stand-alone deferred taxes.
(4) Represents ENLC's interest in Midstream Holdings' maintenance capital expenditures, which is netted against the monthly disbursement of Midstream Holdings' adjusted EBITDA.

Gross Operating Margin

We include gross operating margin as a non-GAAP financial measure. We define gross operating margin as revenues minus cost of purchased gas, NGLs, condensate and crude oil. We present gross operating margin by segment in “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations.” We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because our business is generally to purchase and resell natural gas, NGLs, condensate and crude oil for a margin or to gather, process, transport or market natural gas, NGLs, condensate and crude oil for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. We do not deduct operating expenses from total revenue in calculating gross operating margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

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The following table provides a reconciliation of gross operating margin to operating income:

	Years Ended December 31,		
	2014	2013	2012
	(In millions)		
Total gross operating margin	$1,005.9	$559.6	$479.7
Add (deduct):			
Operating expenses	(278.2)	(156.2)	(149.9)
General and administrative expenses	(97.3)	(45.1)	(41.7)
Depreciation, amortization, and impairments	(280.3)	(187.0)	(161.8)
Gain on sale of property	0.1	—	—
Gain on litigation settlement	6.1	—	—
Operating income	$356.3	$171.3	$126.3

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

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report.

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of the Predecessor, the predecessor to Midstream Holdings, which is the historical predecessor of EnLink Midstream, LLC and (2) for periods on or after March 7, 2014, the results of operations of EnLink Midstream, LLC, after giving effect to the business combination discussed under "Devon Energy Transaction" below. The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon prior to the business combination, including its 38.75% economic interest in GCF. However, in connection with the business combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% economic interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

You should read this discussion in conjunction with the historical financial statements and accompanying notes included in this report. All references in this section to the "Company", as well as the terms "our," "we," "us" and "its" (1) for periods prior to March 7, 2014 refer to the Predecessor and (2) for periods on or after March 7, 2014 refer to EnLink Midstream, LLC, together with its consolidated subsidiaries including the Partnership and Midstream Holdings. All references in this section to the "Partnership" (1) for periods prior to March 7, 2014 refer to the Predecessor and (2) for periods on or after March 7, 2014 refer to EnLink Midstream Partners, LP, together with its consolidated subsidiaries including the Operating Partnership, Midstream Holdings and their consolidated subsidiaries.

Overview

We are a Delaware limited liability company formed in October 2013. Our assets consist of equity interests in EnLink Midstream Partners, LP and EnLink Midstream Holdings, LP. EnLink Midstream Partners, LP is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. EnLink Midstream Holdings, LP, a partnership owned by the Partnership and us, is engaged in the gathering, transmission and processing of natural gas. Our interests in EnLink Midstream Partners, LP and EnLink Midstream Holdings, LP consist of the following:

- 17,431,152 common units representing an aggregate 7% limited partner interest in the Partnership as of December 31, 2014;
- 100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of the Partnership, which owns a 0.7% general partner interest as of December 31, 2014 and all of the incentive distribution rights in the Partnership; and
- 50.0% limited partner interest in Midstream Holdings as of December 31, 2014 and 25% limited partner interest in Midstream Holdings as of February 17, 2015.

Each of the Partnership and Midstream Holdings is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership's or Midstream Holdings' business, as applicable, or to provide for future distributions.

The incentive distribution rights in the Partnership entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

Since we control the general partner interest in the Partnership, we reflect our ownership interest in the Partnership on a consolidated basis, which means that our financial results are combined with the Partnership's financial results and the results of our other subsidiaries. Since the Partnership controls Midstream Holdings through the ownership of its general partner, the financial results of the Partnership consolidate all of Midstream Holdings' financial results. Our consolidated results of operations are derived from the results of operations of the Partnership and also include our deferred taxes, interest of non-controlling partners in the Partnership's net income, interest income (expense) and general and administrative expenses not reflected in the Partnership's results of operations. Accordingly, the discussion of our financial position and results of operations in this “Management’s Discussion and Analysis of Financial Condition and Results of Operations” primarily reflects the operating activities and results of operations of the Partnership and Midstream Holdings.

The Partnership primarily focuses on providing midstream energy services, including gathering, transmission, processing, fractionation, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. The Partnership's midstream energy asset network includes approximately 8,800 miles of pipelines, thirteen natural gas processing plants, seven fractionators, 3.1 million barrels of NGL cavern storage, 11.0 Bcf of natural gas storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. The Partnership manages and reports its activities primarily according to geography. The Partnership has five reportable segments: (1) Texas, which includes its activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes its activities in Cana-Woodford and Arkoma-Woodford Shale areas; (3) Louisiana, which includes its pipelines, processing plants and NGL assets located in Louisiana; (4) ORV, which includes its activities in the Utica and Marcellus Shales and its equity interests in E2 Energy Services, LLC, E2 Appalachian Compression, LLC and E2 Ohio Compression (collectively, "E2"); and (5) Corporate Segment, or Corporate, which includes its equity investments in Howard Energy Partners, or HEP, in the Eagle Ford Shale, its contractual right to the burdens and benefits associated with Devon's ownership interest in GCF in south Texas and its general partnership property and expenses.

The Partnership manages its operations by focusing on gross operating margin because the Partnership's business is generally to purchase and resell natural gas, NGLs, condensate and crude oil for a margin or to gather, process, transport or market natural gas, NGLs, condensate and crude oil for a fee. In addition, the Partnership earns a volume based fee for brine disposal services and condensate stabilization. The Partnership defines gross operating margin as operating revenue minus cost of purchased gas, NGLs, condensate and crude oil. Gross operating margin is a non-generally accepted accounting principle, or non-GAAP, financial measure and is explained in greater detail under "Non-GAAP Financial Measures" under "Item 6. Selected Financial Data."

The Partnership's gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities, the volumes of NGLs handled at its fractionation facilities, the volumes of crude oil and condensate handled at its crude terminals, the volumes of crude oil and condensate gathered, transported, purchased and sold, the volume of brine disposed and the volumes of condensate stabilized. The Partnership generates revenues from eight primary sources:

•purchasing and reselling or transporting natural gas and NGLs on the pipeline systems it owns;

•processing natural gas at its processing plants;

•fractionating and marketing the recovered NGLs;

•providing compression services;

•purchasing and reselling crude oil and condensate;

•providing crude oil and condensate transportation and terminal services;

•providing condensate stabilization services; and

•providing brine disposal services.

The Partnership generally gathers or transports gas owned by others through its facilities for a fee, or it buys natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transports and resells the natural gas at the market index. The Partnership attempts to execute all purchases and sales substantially concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the margin it will receive for each natural gas transaction. The Partnership's gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. The Partnership is also party to certain long-term gas sales commitments that it satisfies through supplies purchased under long-term gas purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time the supplies that it has under contract may decline due to reduced drilling or other causes and the Partnership may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In the Partnership's purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, on occasion the Partnership has entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and it captures the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as margin. Changes in the basis spread can increase or decrease margins.

The Partnership has made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect the Partnership's margins or even result in losses. For example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. The Partnership buys gas for this contract on several different production-area indices on its North Texas Pipeline and sells the gas into a different market area index. The Partnership realizes a loss on the delivery of gas under this contract each month based on current prices. The fair value of this performance obligation was recorded as a result of the March 7, 2014 business combination and was based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of December 31, 2014, the balance sheet reflects a liability of $80.7 million related to this performance obligation. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

The majority of the Partnership's NGL fractionation business, which includes transportation, fractionation, and storage, is under fee-based arrangements. The Partnership is typically paid a fixed fee based on the volume of NGLs transported, fractionated or stored. On the Partnership's Cajun-Sibon pipeline, it buys the mixed NGL stream from its suppliers for an indexed-based price for the component NGLs with a deduction for its fractionation fee. After the NGLs are fractionated, the Partnership sells the fractioned NGL products based on the same indexed-based prices. The operating results of the Partnership's NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With the Partnership's fractionation business, it also has the opportunity for product upgrades for each of the discrete NGL products. The margins the Partnership realizes on the product upgrade from this fractionation business are higher during periods with high liquids prices.

The Partnership generally gathers or transports crude oil owned by others by rail, truck, pipeline and barge facilities for a fee, or it buys crude oil from a producer at a fixed discount to a market index, then transports and resells the crude oil at the market index. The Partnership executes all purchases and sales substantially concurrently, thereby establishing the basis for the margin it will receive for each crude oil transaction. Additionally, the Partnership provides crude oil, condensate and brine services on a volume basis.

The Partnership also realizes gross operating margins from its processing services primarily through three different contract arrangements: processing margins ("margin"), percentage of liquids ("POL") or fixed-fee based. Under margin contract arrangements the Partnership's gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Under fixed-fee based contracts the Partnership's gross operating margins are driven by throughput volume. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision, property insurance, property taxes, repair and maintenance expenses, contract services and utilities. These costs are normally fairly stable across broad volume ranges and therefore do not normally decrease or increase significantly in the short term with decreases or increases in the volume of gas, liquids or crude oil moved through or by the asset.

Our general and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, fees, services and other transaction costs related to acquisitions, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Devon Energy Transaction

On March 7, 2014, ENLC consummated the transactions contemplated by the Agreement and Plan of Merger, dated as of October 21, 2013 (the “Merger Agreement”), among EnLink Midstream, Inc., or EMI, Devon, Acacia Natural Gas Corp I, Inc., formerly a wholly-owned subsidiary of Devon (“New Acacia”), and certain other wholly-owned subsidiaries of Devon pursuant to which EMI and New Acacia each became wholly-owned subsidiaries of ENLC (collectively, the “Mergers”). Upon the closing of the Mergers (the “Closing”), each issued and outstanding share of EMI’s common stock was converted into the right to receive (i) one Common Unit and (ii) an amount in cash equal to approximately $2.06. In addition, ENLC issued 115,495,669 Class B Units to a wholly-owned subsidiary of Devon, which units represent approximately 70% of the outstanding limited liability company interests in ENLC, with the remaining 30% held by the former stockholders of EMI in exchange for a 50% interest in Midstream Holdings. The Class B Units were substantially similar in all respects to the Common Units, except that they were only entitled to a pro rata distribution for the fiscal quarter ended March 31, 2014. The Class B Units automatically converted into Common Units on a one-for-one basis on May 6, 2014.

Also, on March 7, 2014, the Partnership consummated the transactions contemplated by the Contribution Agreement, dated as of October 21, 2013 (the “Contribution Agreement”), among the Partnership, EnLink Midstream Operating, Devon and certain of Devon’s wholly-owned subsidiaries.

Recent Growth Developments

Organic Growth

Ohio River Valley Condensate Pipeline and Condensate Stabilization Facilities. In August 2014, the Partnership announced plans to construct a new 45-mile, eight-inch condensate pipeline and six natural gas compression and condensate stabilization facilities that will service major producer customers in the Utica Shale, including Eclipse Resources. As a component of the project, the Partnership has entered into a long-term, fee-based agreement under which Eclipse Resources will receive compression and stabilization services and has agreed to sell stabilized condensate to the Partnership.

The new-build stabilized condensate pipeline will connect to the Partnership's existing 200-mile pipeline in the ORV, providing producer customers in the region access to premium market outlets through our barge facility on the Ohio River and rail terminal in Ohio. The pipeline, which is expected to be complete in the second half of 2015, is expected to have an initial capacity of approximately 50,000 Bbls/d.

The Partnership also expects to build and operate six natural gas compression and condensate stabilization facilities in Noble, Belmont, and Guernsey counties in Ohio. Upon completion, the facilities will have a combined capacity of approximately 560 MMcf/d of natural gas compression and approximately 41,500 Bbls/d of condensate stabilization. The first two compression and condensate stabilization facilities began operations during the fourth quarter of 2014 and the remaining four facilities are expected to be operational by the end of 2015.

In support of the project, the Partnership plans to leverage and expand its existing midstream assets in the region, including increasing condensate storage capacity and handling capabilities at its barge terminal on the Ohio River. The Partnership will add approximately 130,000 barrels of above ground storage, bringing its total storage capacity at the barge facility to over 360,000 barrels.

Marathon Petroleum Joint Venture. The Partnership has entered into a series of agreements with MPL Investment LLC, a subsidiary of Marathon Petroleum Corporation (“Marathon Petroleum”), to create a 50/50 joint venture named Ascension Pipeline Company, LLC. This joint venture will build a new 30-mile NGL pipeline connecting the Partnership’s existing Riverside fractionation and terminal complex to Marathon Petroleum’s Garyville refinery located on the Mississippi River. The bolt-on project to the Partnership’s Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, the Partnership will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

Cajun-Sibon Phases I and II. In Louisiana, the Partnership has transformed its business that historically has been focused on processing offshore natural gas to a business that is now focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market historically has relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II now bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

The pipeline expansion and the Eunice fractionation expansion under Phase I were completed and commenced operation in November 2013. Phase II of the Cajun-Sibon expansion, which was completed and commenced operation in September 2014, increased the Cajun-Sibon pipeline capacity by an additional 50,000 Bbls/d to approximately 130,000 Bbls/d and added a new 100,000 Bbl/d fractionator at the Partnership's Plaquemine gas processing complex. The throughput of the pipeline averaged 109,900 Bbls/d during the fourth quarter of 2014. The Partnership's fractionators in south Louisiana averaged approximately 98,300 Bbls/d during the fourth quarter of 2014.

The Partnership believes the Cajun-Sibon project represents a tremendous growth step by leveraging its Louisiana assets and also by creating a significant platform for continued growth of the Partnership's NGL business. The Partnership believes this project, along with existing assets, will provide a number of additional opportunities to grow this business, including expanding market optionality and connectivity, upgrading products, expanding rail imports, exporting NGLs and expanding fractionation and product storage capacity.

Bearkat Natural Gas Gathering and Processing System. In September 2014, the Partnership completed construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin called Bearkat. The natural gas processing complex includes treating, processing and gas takeaway solutions for regional producers. The project, which is fully owned by the Partnership, is supported by a 10-year, fee-based contract.

Bearkat is strategically located near the Partnership's existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant has an initial capacity of 60 MMcf/d, increasing the Partnership’s total operational

processing capacity in the Permian to approximately 115 MMcf/d. The Partnership also completed construction of a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan counties.
During 2014, the Partnership constructed a new 35-mile, 12-inch diameter high-pressure pipeline to provide gathering capacity for the Bearkat natural gas processing complex. The pipeline has an initial capacity of approximately 100 MMcf/d and

provides gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The pipeline commenced operation in the fourth quarter of 2014.

Growing with Devon

West Texas Expansion. The Partnership is expanding its natural gas gathering and processing system in the Permian Basin by constructing a new natural gas processing plant and expanding the Partnership's rich gas gathering system. The new 120 MMcf/d gas processing plant will be strategically located on the north end of the Partnership's existing midstream assets and will offer additional gas processing capabilities to producer customers in the region, including Devon. Due to the impact from the current commodity environment and a shift in producers' drilling expectations, we are delaying construction on the processing plant until late 2015. Upon completion, the Partnership's total operated processing capacity in the region will be approximately 240 MMcf/d.

As a part of the expansion, the Partnership has signed a long-term, fee-based agreement with Devon to provide gathering and processing services for over 18,000 acres under development in Martin County. The Partnership constructed multiple low pressure gathering pipelines and a new 23-mile, 12-inch high pressure gathering pipeline that will tie into the previously announced Bearkat natural gas gathering system. The new pipelines commenced operation in January 2015.

Drop Downs

Midstream Holdings. On February 17, 2015, Acacia, a wholly-owned subsidiary of ENLC, sold a 25% limited partner interest in Midstream Holdings (the "Transferred Interest") to the Partnership in a drop-down transaction (the "EMH Drop Down"). As consideration for the Transferred Interest, the Acacia received 31.6 million Class D Common Units in the Partnership. The Partnership's Class D Common Units are substantially similar in all respects to the Partnership's Common Units, except that they will only be entitled to a pro rata distribution for the fiscal quarter ended March 31, 2015. The Partnership's Class D Common Units will automatically convert into the Partnership's Common Units on a one-for-one basis on the first business day following the record date for distribution payments with respect to the distribution for the quarter ended March 31, 2015. After giving effect to the EMH Drop-Down, the Partnership indirectly owns a 75% limited partner interest in Midstream Holdings, with Acacia owning the remaining 25% limited partner interest in Midstream Holdings.

E2 Drop Down. On October 22, 2014, EMI, a wholly-owned subsidiary of ENLC, sold 100% of the Class A Units and 50% of the Class B Units (collectively, the "E2 Appalachian Units") in E2 Appalachian Compression, LLC ("E2 Appalachian"), and 93.7% of the Class A Units (the "Energy Services Units" and, together with the E2 Appalachian Units, the "Purchased Units") in E2 Energy Services, LLC ("Energy Services" and together with E2 Appalachian "E2"), to the Partnership. The total consideration paid by the Partnership to EMI for the Purchased Units included (i) $13.0 million in cash for the Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in the Partnership for the E2 Appalachian Units. The remaining 50% of the Class B Units in E2 Appalachian are owned by members of the E2 Appalachian management team and are designed to provide such management team members with equity incentives.

E2 Investment. On October 10, 2014, we purchased 100% of Class A units and 50% of Class B Units of E2 Appalachian Compression, LLC owned by E2 management for $7.0 million and $5.5 million, respectively. E2 constructed three natural gas compressor stations and condensate stabilization facilities located in Noble and Monroe counties in the southern portion of the Utica Shale play in Ohio.

Acquisitions

Coronado Midstream. On February 1, 2015, the Partnership entered into an agreement with Reliance Midstream, LLC, a Texas limited liability company ("Reliance"), Windsor Midstream LLC, a Delaware limited liability company ("Windsor"), Wallace Family Partnership, LP, a Texas limited partnership ("Wallace"), and Ted Collins, Jr., an individual residing in Midland, Texas ("Collins" and, collectively with Reliance, Windsor and Wallace, the "Sellers," and each, a "Seller"), and Reliance, in its capacity as representative of the Sellers, to acquire all of the equity interests in Coronado Midstream Holdings LLC, the parent company of Coronado Midstream LLC, which owns natural gas gathering and processing facilities in the Permian Basin for approximately $600.0 million in cash and equity, subject to certain adjustments. Coronado operates three cryogenic gas processing plants and a gas gathering system in the North Midland Basin including approximately 270 miles of gathering pipelines, 175 MMcf/d of processing capacity and 35,000 horsepower of compression. The Coronado system is underpinned by long-term contracts, which include the dedication of production from over 190,000 acres.

LPC Crude Oil Marketing. On January 31, 2015, the Partnership, through one of its wholly owned subsidiaries, acquired LPC, which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $100.0 million. LPC is an integrated crude oil logistics service provider with operation throughout the Permian Basin. LPC's integrated logistics services are supported by 41 tractor trailers, 13 pipeline injection stations and 67 miles of crude oil gathering pipeline.

Natural Gas Pipeline Assets. On November 1, 2014, the Partnership acquired Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana, for $234.0 million, subject to certain adjustments. These natural gas pipeline assets include the following:

- Bridgeline System: approximately 990 miles of natural gas pipelines in southern Louisiana with a total system capacity of approximately 900 MMcf/d;
- Sabine Pipeline: approximately 130 miles of natural gas pipelines in Texas and southern Louisiana with a total capacity of approximately 300 MMcf/d;
- Chandeleur System: approximately 215 miles of offshore Mississippi and Alabama pipelines with a total capacity of approximately 300 MMcf/d;
- Storage Assets: three caverns located in southern Louisiana with a combined working capacity of approximately 11.0 Bcf of natural gas, including two near Sorrento, LA with a capacity of approximately 4.0 Bcf and one inactive cavern near Napoleonville, LA with approximately 7.0 Bcf of capacity; and
- Henry Hub: ownership and management of the title tracking services offered at the Henry Hub, the delivery location for the New York Mercantile Exchange (the “NYMEX”) natural gas futures contracts. Henry Hub is connected to 13 major interstate and intrastate natural gas pipeline and storage systems.

Issuance of Common Units by the Partnership

In November 2014, the Partnership issued 12,075,000 common units representing limited partner interests in the Partnership at an offering price of $28.37 per unit for net proceeds of $332.3 million. The net proceeds from the common units offering were used for capital expenditures and general partnership purposes.

In October 2014, the Partnership issued 1,016,322 common units to ENLC representing limited partner interests in the Partnership as partial consideration for E2 Appalachian Units.

In May 2014, the Partnership entered into an Equity Distribution Agreement (the “EDA”) with BMO Capital Markets Corp. (“BMOCM”). Pursuant to the terms of the EDA, the Partnership may from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Through December 31, 2014, the Partnership sold an aggregate of 2.4 million common units under the EDA, generating proceeds of approximately $71.9 million (net of approximately $0.7 million of commissions to BMOCM). The Partnership used the net proceeds for general partnership purposes.

On November 7, 2014, Partnership entered into an Equity Distribution Agreement (the “BMO EDA”) with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC (collectively, the “Sales Agents”) to sell up to $350.0 million in aggregate gross sales of the Partnership’s common units representing limited partner interests from time to time through an “at the market” equity offering program. The Partnership may also sell Common Units to any Sales Agent as principal for the Sales Agent’s own account at a price agreed upon at the time of sale. The Partnership has no obligation to sell any of the Common Units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA. Through December 2014, the Partnership sold an aggregate of 0.3 million common units under the BMO EDA, generating proceeds of approximately $7.8 million (net of approximately $0.1 million of commissions). The Partnership used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

Results of Operations

The table below sets forth certain financial and operating data for the periods indicated. We manage our operations by focusing on gross operating margin which we define as operating revenue less cost of purchased gas, NGLs, condensate and crude oil as reflected in the table below.

Items Affecting Comparability of Our Financial Results

Our historical financial results discussed below may not be comparable to our future financial results, and our financial results for the year ended December 31, 2013 may not be comparable to our financial results for the year ended December 31, 2014 for the following reasons:

- In connection with the business combination, Midstream Holdings entered into new agreements with Devon that were effective on March 1, 2014 pursuant to which Midstream Holdings provides services to Devon under fixed-fee arrangements in which Midstream Holdings does not take title to the natural gas gathered or processed or the NGLs it fractionates. Prior to the effectiveness of these agreements, the Predecessor provided services to Devon under a percent-of-proceeds arrangement in which it took title to the natural gas it gathered and processed and the NGLs it fractionated.

- Prior to March 7, 2014, our financial results only included the assets, liabilities and operations of our Predecessor. Beginning on March 7, 2014, our financial results also consolidate the assets, liabilities and operations of the legacy business of the Partnership prior to giving effect to the business combination.

- Subsequent to March 7, 2014, we own a 50% direct ownership interest in Midstream Holdings and indirectly own an additional interest of approximately 3% of Midstream Holdings through our ownership in the Partnership which owns the remaining 50% interest in Midstream Holdings rather than the 100% ownership reflected as part of our Predecessor's historical financial results. Our financial statements after March 7, 2014 consolidate all of Midstream Holdings' financial results with ours in accordance with GAAP and ENLK's 47% interest not owned by us in Midstream Holdings is reflected as a non-controlling interest. On February 17, 2015, Acacia contributed a 25% interest in Midstream Holdings to the Partnership in exchange for 31.6 million Class D Common Units in the Partnership. See "Recent Growth Developments."

- Our financial statements for the year ended December 31, 2014 report financial results according to operating segments based principally upon geographic regions served. The Predecessor had no operations for certain of those reporting segments.

- The Predecessor's historical assets comprised all of Devon's U.S.-midstream assets and operations. However, only its assets serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as a contractual right to the burdens and benefits of its 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the consummation of the business combination. Assets that were not contributed to Midstream Holdings are included in discontinued operations.

- All historical affiliated transactions prior to March 7, 2014 related to our continuing operations were net settled within our combined financial statements because these transactions related to Devon and were funded by Devon's working capital. Beginning on March 7, 2014, all our transactions are funded by our working capital. This will impact the comparability of our cash flow statements, working capital analysis and liquidity discussion.

	For years ended December 31,		
	2014	2013	2012
	(in millions, except volumes)		
Texas Segment			
Revenues	$1,067.2	$1,549.1	$1,357.2
Purchased gas and NGLs	(490.9)	(1,130.4)	(983.3)
Total gross operating margin	$576.3	$418.7	$373.9
Louisiana Segment			
Revenues	$1,925.5	$—	$—
Purchased gas, NGLs and crude oil	(1,754.2)	—	—
Total gross operating margin	$171.3	$—	$—
Oklahoma Segment			
Revenues	$318.8	$746.8	$550.6
Purchased gas and NGLs	(142.5)	(605.9)	(444.8)
Total gross operating margin	$176.3	$140.9	$105.8
Ohio River Valley Segment			
Revenues	$261.3	$—	$—
Purchased crude oil and condensate	(201.4)	—	—
Total gross operating margin	$59.9	$—	$—
Corporate			
Revenues	$(72.4)	$—	$—
Purchased gas, NGLs and crude oil	94.5	—	—
Total gross operating margin	$22.1	$—	$—
Total			
Revenues	$3,500.4	$2,295.9	$1,907.8
Purchased gas, NGLs, crude oil and condensate	(2,494.5)	(1,736.3)	(1,428.1)
Total gross operating margin	$1,005.9	$559.6	$479.7
Midstream Volumes:			
Texas (1)			
Gathering and Transportation (MMBtu/d)	2,958,000	2,102,000	2,127,000
Processing (MMBtu/d)	1,146,000	811,000	753,000
Louisiana (2)			
Gathering and Transportation (MMBtu/d)	615,200	—	—
Processing (MMBtu/d)	547,000	—	—
NGL Fractionation (Gals/d) (4)	3,804,300	—	—
Oklahoma (3)			
Gathering and Transportation (MMBtu/d)	471,000	390,000	351,000
Processing (MMBtu/d)	442,000	400,000	340,000
ORV (2)			
Crude Oil Handling (Bbls/d)	16,300	—	—
Brine Disposal (Bbls/d)	4,700	—	—

(1) Volumes include volumes per day based on 365 day period for the years ended December 31, 2014, 2013 and 2012 for Midstream Holdings operations. Volumes include volumes per day based on the 300 day period from March 7 to December 31, 2014 for the year ended December 31, 2014 for the Partnership's legacy operations in Texas.
(2) Volumes include volumes per day based on the 300 day period from March 7 to December 31, 2014 for the year ended December 31, 2014 for the Partnership's legacy operations. Midstream Holdings does not have any operations in Louisiana or Ohio.

(3) Volumes include volumes per day based 365 day period for the years ended December 31, 2014, 2013 and 2012 respectively, for Midstream Holdings operations. The Partnership did not have any legacy operations in Oklahoma.
(4) NGL fractionation volumes for the quarterly periods ended March 31, 2014, June 30, 2104 and September 30, 2014 reflected in our quarterly reports on Form 10-Q for the respective periods were overstated due to a clerical error in compiling such information. The corrected NGL fractionation volumes based on gallons per day for the quarters ended March 31, 2014, June 30, 2014 and September 30, 2014 were 3,336,800, 3,360,400 and 2,727,400, respectively, as compared to the previously reported volumes of 3,291,900, 4,377,300 and 4,073,500, respectively.
Year ended December 31, 2014 Compared to Year ended December 31, 2013
Gross Operating Margin. Gross operating margin was $1,005.9 million for the year ended December 31, 2014 compared to $559.6 million for the year ended December 31, 2013, an increase of $446.3 million, or 79.8%. Of this increase in gross operating margin, $386.8 million is attributable to the legacy Partnership assets associated with the business combination effective on March 7, 2014. Approximately $59.5 million of the increase in gross operating margin is related to an increase in gross operating margin at Midstream Holdings as a result of the new fixed-fee arrangements with Devon entered into in connection with the business combination.
Operating Expenses. Operating expenses were $278.2 million for the year ended December 31, 2014 compared to $156.2 million for the year ended December 31, 2013, an increase of $122.0 million, or 78.1%. Of this increase in operating expenses,$145.6 million is attributable to the legacy Partnership assets, partially offset by a decrease in Midstream Holdings' operating expenses of $23.6 million due to both lower personnel and contract labor expense and a decrease in compressor maintenance expense.
General and Administrative Expenses. General and administrative expenses were $97.3 million for the year ended December 31, 2014 compared to $45.1 million for the year ended December 31, 2013, an increase of $52.2 million, or 115.7%. General and administrative expenses for the year ended December 31, 2014 reflect expenses associated with the new combined operations of the legacy Partnership and Midstream Holdings since March 7, 2014, including $3.3 million for transition service costs from Devon, together with general and administrative expenses of Midstream Holdings prior to March 7, 2014. General and administrative expenses for the year ended December 31, 2013 reflect expenses for Midstream Holdings which primarily consisted of costs allocated by Devon for shared general and administrative services.
Depreciation and Amortization. Depreciation and amortization expenses were $280.3 million for the year ended December 31, 2014 compared to $187.0 million for the year ended December 31, 2013, an increase of $93.3 million, or 49.9%. The increase in depreciation and amortization expenses result from an increase in depreciation expense of $137.9 million related to the legacy Partnership assets acquired in March 2014 together with additional depreciation for net asset additions during 2014. The increase was partially offset by a decrease of $44.6 million in depreciation and amortization expenses related to Midstream Holdings primarily due to the change in depreciation methodology from the units-of-production method to the straight-line method which accounted for $29.4 million of such decrease. The remaining $5.6 million decrease was related to a change in the annual units-of-production rate partially offset by a $1.7 million increase related to assets placed in service during 2013.
Gain on Litigation Settlement. We recognized a gain on the settlement of a lawsuit of $6.1 million for the year ended December 31, 2014 due to a partial settlement of our claims against Texas Brine and its insurers. Additional claims related to this matter remain outstanding.
Interest Expense. Interest expense was $49.8 million for the year ended December 31, 2014. There was no interest expense for the year ended December 31, 2013 as Midstream Holdings did not have any debt. Net interest expense consists of the following (in millions):

	Year Ended December 31, 2014
Senior notes	$55.6
Bank credit facility	8.0
Capitalized interest	(11.5)
Amortization of debt issue costs and net discount (premium)	(1.0)

Cash settlements on interest rate swap	(3.6)
Other	2.3
Total	$49.8

Income from Equity Investments. Income from equity investments was $18.9 million for the year ended December 31, 2014 compared to $14.8 million for the year ended December 31, 2013, an increase of $4.1 million. Of this increase in income from equity investments, $1.8 million is attributable to legacy Partnership equity investments. The remaining increase relates to the Partnership's investment in GCF due to an improvement in turnaround downtime experience as compared to the 2013 period.

Income Tax Expense. Income tax expense was $76.4 million for the year ended December 31, 2014 as compared to income tax expense of $67.0 million for the year ended December 31, 2013, an increase of $9.4 million. The increase in income tax expense primarily relates to an increase in our taxable income and an increase in the effective tax rate from 36% to 37.5% between periods.

Net Income (Loss) from Discontinued Operations. Net income from discontinued operations was $1.0 million for the year ended December 31, 2014 as compared to a net loss of $3.6 million for the year ended December 31, 2013, an increase of $4.6 million. The increase is due to Midstream Holdings' discontinued operations for the year ended December 31, 2013 which included assets that were sold during 2013, while year ended December 31, 2014 includes Predecessor assets that were not contributed to Midstream Holdings as part of the business combination.

Year ended December 31, 2013 Compared to Year ended December 31, 2012

Gross Operating Margin. Gross operating margin was $559.6 million for the year ended December 31, 2013 compared to $479.7 million for the year ended December 31, 2012, an increase of $79.9 million, or 16.7%. Higher gathering, processing and transportation volumes were responsible for an increase in gross operating margin of $32.3 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Higher volumes were primarily the result of NGL production increasing 25%, resulting in $34.1 million of higher gross operating margin. The increase in NGL production was largely driven by higher inlet volumes at the Cana processing facility, improved efficiencies at the Cana and Bridgeport processing facilities and unplanned downtime impacting Midstream Holdings' Bridgeport processing facility in 2012. The increase in NGL production was partially offset by slightly lower throughput volumes, primarily on the Predecessor's East Johnson and Northridge gathering systems.

Changes in pricing led to an increase in gross operating margin of $48.4 million for the year ended December 31, 2013
compared to the year ended December 31, 2012. Natural gas pipeline fees increased 15%, which resulted in $44.2 million of
additional revenues. Additionally, higher residue natural gas prices contributed an additional $32.4 million to gross operating margin. These increases were partially offset by lower margins of $28.2 million primarily due to NGL price declines.

Operating Expenses. Operating expenses were $156.2 million for the year ended December 31, 2013 compared to $149.9 million for the year ended December 31, 2012, an increase of $6.3 million, or 4.2%. The increase primarily relates to an increase of $4.8 million related to higher ad valorem tax assessments on Midstream Holdings' Cana assets offset by decrease in other expenses.

General and Administrative Expenses. General and administrative expenses were $45.1 million for the year ended December 31, 2013 compared to $41.7 million for the year ended December 31, 2012, an increase of $3.4 million, or 8.2%. The increase is primarily due to higher employee compensation and benefits.

Depreciation and Amortization. Depreciation and amortization expenses were $187.0 million for the year ended December 31, 2013 compared to $145.4 million for the year ended December 31, 2012, an increase of $41.6 million, or 28.6%. The increase primarily resulted from higher capitalized costs on the Cana system. Devon and other producers have continued to grow natural gas production in the Cana-Woodford Shale. As a result, we have increased our throughput capacity by expanding our pipeline and gathering systems and our Cana processing facility.

Income from Equity Investments. Income from equity investments was $14.8 million for the year ended December 31, 2013 compared to $2.0 million for the year ended December 31, 2012. The increase relates to our investment in GCF due to an increase in volumes.

Income Tax Expense. Income tax expense was $67.0 million for the year ended December 31, 2013 as compared to income tax expense of $46.2 million for the year ended December 31, 2012, an increase of $20.8 million. This increase primarily relates to an increase in taxable income related to the Predecessor. During 2013 and 2012, effective income tax rates were 36% for both periods. These rates differed from the U.S. statutory income tax rate due to the effect of state income taxes.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical.

Our critical accounting policies are discussed below. See Note 2 of the Notes to Consolidated Financial Statements for further details on our accounting policies.

Revenue Recognition and Commodity Risk Management. We recognize revenue for sales or services at the time the natural gas, NGL, condensate or crude oil is delivered or at the time the service is performed. We generally accrue one month of sales and the related gas, NGL, condensate or crude oil purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

We utilize extensive estimation procedures to determine the sales and cost of gas, NGL, condensate or crude oil purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. We use actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as “actualization”. Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month's accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; liquids recoveries being higher or lower than estimated because gas processed through the plants was richer or leaner than estimated; the estimated impact of weather patterns being different from the actual impact on sales and purchases; and pipeline maintenance or allocation causing actual deliveries of gas to be different than estimated. We believe that our accrual process for sales and purchases provides a reasonable estimate of such sales and purchases.

We engage in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas, NGLs, crude oil and condensate. We also manage our price risk related to future physical purchase or sale commitments by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas, NGL and crude oil prices.

We use derivatives to hedge against changes in cash flows related to product prices, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives and hedging instruments are recognized as assets or liabilities at fair value. We manage our price risk related to future physical purchase or sale commitments for energy trading activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance future commitments and significantly reduce risk related to the movement in natural gas prices. However, we are subject to counter-party risk for both the physical and financial contracts. Our energy trading contracts qualify as derivatives and we use mark-to-market accounting for both physical and financial contracts of the energy trading business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to energy trading activities are recognized currently in earnings as gain on derivatives.

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, we evaluate long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, NGLs and crude oil, volume of gas, NGLs and crude oil available to the asset, markets available to the asset, operating expenses, and future natural gas, NGL product and crude oil prices. The amount of availability of gas, NGLs and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas and crude oil prices. Projections of gas, NGL and crude oil volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas, NGLs, crude oil and condensate supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas, NGLs, crude oil and condensate exploration and production activities will not occur or be successful;

- our dependence on certain significant customers, producers and transporters of natural gas, NGLs, crude oil and condensate; and
- competition from other midstream companies, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

Impairment of Goodwill. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31st, and also whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

At October 31, 2014, the date of our last impairment test, the fair values of our Texas, Louisiana, Oklahoma, ORV and Corporate reporting units exceeded their related carrying values. The fair value of our Texas, Oklahoma, ORV and Corporate reporting units substantially exceeded their carrying value. However, the fair value of our Louisiana reporting is not substantially in excess of its carrying value. As of October 31, 2014, the fair value of our Louisiana reporting unit exceeded its carrying value by approximately 14 percent. As of December 31, 2014, we had $273.1 million of goodwill allocated to the Louisiana reporting unit.

Significant decreases to our unit price, decreases in commodity prices or negative deviations from projected Louisiana reporting unit earnings could result in a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period. Due to the inter-relationship of the various estimates involved in assessing goodwill for impairment, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates.

Depreciation Expense and Cost Capitalization. Our assets consist primarily of natural gas, NGL, condensate and crude oil gathering pipelines, processing plants, condensate stabilization facilities, transmission pipelines and trucks. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed assets through the recording of depreciation expense. We capitalize the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred. Historically, Midstream Holdings depreciated certain property, plant, and equipment using the units-of-production method. As a result of the business combination, Midstream Holdings is operated as an independent midstream company and thus no longer has access to Devon's proprietary reserve and production data historically used to compute depreciation under the units-of-production method. Additionally, the existing contracts with Devon were revised to a fee-based arrangement with minimum volume commitments. Effective March 7, 2014, the Partnership changed its method of computing depreciation for these assets to the straight-line method, consistent with the depreciation method applied to the Partnership's legacy assets. In accordance with FASB ASC 250, the Partnership determined that the change in depreciation method is a change in accounting estimate, and accordingly, the straight-line method will be applied on a prospective basis. This change is considered preferable because the straight-line method more accurately reflects the pattern of usage and the expected benefits of such assets.

Certain assets such as land, NGL line pack, natural gas line pack and crude oil line pack are non-depreciable. The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, we may review depreciation estimates to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

Commodity Price Risk

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We are subject to significant risks due to fluctuation in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. Processing margin and POL contracts are two types of contracts under which we process gas and are exposed to commodity price risk. For the year ended December 31, 2014, approximately 1.68% of our processed gas arrangements, based on gross operating margin, were processed under POL contracts. A portion of the volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. Under these contracts we receive a fee in the form of a percentage of the liquids recovered and the producer bears all the costs of the natural gas volumes lost (“shrink”). Accordingly, our revenues under these contracts are directly impacted by the market price of NGLs.

We also realize processing gross operating margin under margin contracts and spot purchases. For the year ended December 31, 2014, approximately 2.1% of our processed gas arrangements, based on gross operating margin, was processed under margin contracts and spot purchases. We have a number of margin contracts on our Plaquemine and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas shrink and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR.

We are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of natural gas, NGLs, condensate and crude oil connected to or near our assets and on our margins for transportation between certain market centers. Low prices for these products could reduce the demand for our services and volumes on our systems.

In the past, the prices of oil, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2014 ranged from a high of $107.26 per Bbl in June 2014 to a low of $53.27 per Bbl in December 2014. Weighted average NGL prices in 2014 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a high of $1.22 per gallon in February 2014 to a low of $0.45 per gallon in December 2014. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2014 ranged from a high of $7.94 per MMBtu in March 2014 to a low of $2.75 per MMBtu in December 2014.

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, NGLs, condensate and crude oil we gather and process. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. For a discussion of our risk management activities, please read “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.”

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $457.3 million, $330.3 million and $209.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. Operating cash flows and changes in working capital for 2014, 2013 and 2012 were as follows (in millions):

	Years Ended December 31,		
	2014	2013	2012
Operating cash flows before working capital	$580.9	$338.2	$229.8
Changes in working capital	(123.6)	(7.9)	(20.1)
Total	$457.3	$330.3	$209.7

The primary reason for the increase in cash flows before working capital of $242.7 million from 2013 to 2014 relates to an increase in gross operating margin from the acquired legacy Partnership assets and Midstream Holdings assets. The decrease in working capital for 2014 related to fluctuations in trade receivable and payable balances is due to timing of collection and payments and changes in inventory balances due to normal operating fluctuations. Further, prior to March 7, 2014, all cash receipts for the Predecessor were deposited into Devon’s bank accounts, and all cash disbursements were made from these accounts. Cash transactions handled by Devon were reflected in intercompany advances between Devon and the Predecessor, all of which were settled through an adjustment to equity and reflected in cash flows from financing activities. Subsequent to March 7, 2014, Midstream Holdings handles all of its cash transactions and the changes in working capital are reflected in our cash flows from operating activities.

The increase in cash flows from 2013 to 2012 is primarily driven by the fluctuations in volume and price described previously in results of operations.

Cash Flows from Investing Activities. Net cash used in investing activities was $1,041.3 million, $243.2 million and $352.4 million for the years ended December 31, 2014, 2013 and 2012, respectively. Our primary use of cash related to investing activities for the years ended December 31, 2014, 2013 and 2012 was acquisition costs and capital expenditures, net of accrued amounts, and an investment in equity investments as follows (in millions):

	Years Ended December 31,		
	2014	2013	2012
Growth capital expenditures	$726.5	$180.8	$249.5
Maintenance capital expenditures	37.1	63.5	87.7
Acquisition of business and asset purchases	283.0	—	—
Proceeds from sale of property	(0.1)	—	—
Investment in equity investments	5.7	—	17.1
Distribution from equity investment company in excess of earnings	(10.9)	(1.1)	(1.9)
Total	$1,041.3	$243.2	$352.4

Cash Flows from Financing Activities. Net cash provided by financing activities was $652.4 million and $86.2 million for the years ended December 31, 2014 and 2012, respectively, and net cash used in financing activities was 151.2 million for the year ended 2013. Our primary financing activities subsequent to March 7, 2014 consist of the following (in millions):

	Year Ended December 31, 2014
Net borrowings (repayments) under the Partnership's credit facility	$(140.0)
Net repayments on the Company's credit facility	(75.1)
Net repayments on E2 credit facility	(13.8)
The Partnership's senior unsecured notes borrowings	1,600.7
Redemption of the Partnership's 2018 notes	(760.3)
Partial redemption of the Partnership's 2022 notes	(36.4)
Net repayments under capital lease obligations	(3.0)
Debt refinancing costs	(19.7)
Proceeds from issuance of Partnership units	412.0

Distributions to unitholders and non-controlling partners in the Partnership are also primary uses of cash in financing activities. Total cash distributions made during the year ended December 31, 2014 were as follows (in millions):

	Year ended December 31, 2014 (1)
Distributions to members	$89.0
Non-controlling partner distributions	204.3
Total	$293.3

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(1) Excludes distribution declared for the fourth quarter of 2014, which was paid on February 13, 2015.

Prior to the business combination, Midstream Holdings’ continuing operations had no separate cash accounts. The owner contributions and distributions represent the net amount of all transactions that were settled with adjustments to equity. Midstream Holdings had distributions of $21.3 million to Devon for the year ended December 31, 2014 (relating to the period from January 1, 2014 to March 6, 2014), distributions to Devon of $151.2 million for the year ended December 31, 2013 and contributions from Devon of $87.8 million for the year ended December 31, 2012.

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility. The Partnership borrows money under the Partnership's credit facility to fund checks as they are presented. As of December 31, 2014, we had approximately $749.1 million of available borrowing capacity under this facility. Change in drafts payable for 2014 was as follows (in millions):

	Years ended December 31,		
	2014	2013	2012
Increase (decrease) in drafts payable	$10.2	$—	$(1.6)

Capital Requirements. Our 2015 capital budget includes around $500.0 million of identified growth projects, including capitalized interest. The Partnership's primary capital projects for 2015 include the construction of its ORV condensate pipeline, Bearkat plant facilities and West Texas expansion project. During 2014, the Partnership invested in several capital projects which primarily included the expansion of the Cajun-Sibon NGL Pipeline and the construction of the Bearkat facilities. See “Item 1. Business—Recent Growth Developments” for further details.
The Partnership expects to fund its 2015 maintenance capital expenditures of approximately $50.0 million from operating cash flows. The Partnership expects to fund the growth capital expenditures from the proceeds of borrowings under its bank credit facility discussed below and proceeds from other debt and equity sources. In 2015, it is possible that not all of the planned projects will be commenced or completed. The Partnership's ability to pay distributions to its unitholders, and to fund planned capital expenditures and to make acquisitions will depend upon its future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond its control.
Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2014, 2013 and 2012.
Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2014 is as follows (in millions):

	Payments Due by Period						
	Total	2015	2016	2017	2018	2019	Thereafter
Long-term debt obligations	$1,762.5	$—	$—	$—	$—	$400.0	$1,362.5
Partnership's bank credit facility	237.0	—	—	—	—	237.0	—
Other Debt	0.4	0.2	0.1	0.1	—	—	—
Interest payable on fixed long-term debt obligations	1,403.8	79.6	81.3	81.3	81.3	75.9	1,004.4
Capital lease obligations	23.0	4.8	4.8	6.8	2.9	1.6	2.1
Operating lease obligations	119.1	11.6	9.2	6.6	11.5	9.0	71.2
Purchase obligations	86.8	86.8	—	—	—	—	—
Delivery contract obligation	80.7	17.9	17.9	17.9	17.9	9.1	—
Inactive easement commitment*	8.0	1.0	1.0	1.0	1.0	1.0	3.0
Uncertain tax position obligations	2.0	2.0	—	—	—	—	—
Total contractual obligations	$3,723.3	$203.9	$114.3	$113.7	$114.6	$733.6	$2,443.2

* Amounts related to inactive easements paid as utilized with remaining balance of easements not utilized due at end of 10 years.

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.
The interest payable under the Partnership's credit facility and the Company's credit facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates, which will vary from time to time. However, given the same borrowing amount and rates in effect at December 31, 2014 the Partnership's cash obligation for interest expense on its credit facility would be approximately $4.5 million per year. The Company's credit facility had no outstanding borrowing as of December 31, 2014.

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Indebtedness

As of December 31, 2014, long-term debt consisted of the following (in millions):

	2014
Partnership credit facility (due 2019), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2014 was 1.9%	$237.0
Company bank credit facility (due 2019)	—
The Partnership's senior unsecured notes (due 2019), net of discount of $0.5 million, which bear interest at the rate of 2.70%	399.5
The Partnership's senior unsecured notes (due 2022), including a premium of $21.9 million, which bear interest at the rate of 7.125%	184.4
The Partnership's senior unsecured notes (due 2024), including a premium of $3.2 million, which bear interest at the rate of 4.40%	553.2
The Partnership's senior unsecured notes (due 2044), net of discount of $0.3 million, which bear interest at the rate of 5.60%	349.7
The Partnership's senior unsecured notes (due 2045), net of discount of $1.7 million, which bear interest at the rate of 5.05%	298.3
Other Debt	0.4
Debt classified as long-term	$2,022.5

Company Credit Facility. On March 7, 2014, the Company entered into a new $250.0 million revolving credit facility, which includes a $125.0 million letter of credit subfacility (the “credit facility”). The Company used borrowings under the credit facility to repay outstanding borrowings under the margin loan facility of XTXI Capital, LLC (a former wholly-owned subsidiary of EnLink Midstream, Inc.), which was paid in full and terminated on March 7, 2014. Our obligations under the credit facility are guaranteed by two of our wholly-owned subsidiaries and secured by first priority liens on (i) 17,431,152 Partnership common units and the 100% membership interest in the General Partner indirectly held by us, (ii) the 100% equity interest in each of our wholly-owned subsidiaries held by us, (iii) the limited partner interest in Midstream Holdings held by us and (iv) any additional equity interests subsequently pledged as collateral under the credit facility.

The credit facility will mature on March 7, 2019. The credit facility contains certain financial, operational and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter, and include (i) maintaining a maximum consolidated leverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated funded indebtedness to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) of 4.00 to 1.00, provided that the maximum consolidated leverage ratio is 4.50 to 1.00 during an acquisition period (as defined in the credit facility) and (ii) maintaining a minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) of 2.50 to 1.00 at all times prior to the occurrence of an investment grade event (as defined in the credit facility).

Borrowings under the credit facility bear interest, at our option, at either the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent’s prime rate) plus an applicable margin. The applicable margins vary depending on our leverage ratio. Upon breach by us of certain covenants governing the credit facility, amounts outstanding under the credit facility, if any, may become due and payable immediately and the liens securing the credit facility could be foreclosed upon.

As of December 31, 2014, there were no borrowings under the credit facility, leaving $250.0 million available for future borrowing based on the borrowing capacity of $250.0 million.

Partnership Credit Facility. On February 20, 2014, the Partnership entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the “Partnership credit facility”). On February 5, 2015, the commitments under the Partnership credit facility were increased to $1.5 billion and the maturity date was extended by a year. The Partnership credit facility will mature on the sixth anniversary of the initial funding date, which was March 7, 2014, unless the Partnership requests, and the requisite lenders agree, to extend it pursuant to its terms. The Partnership credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the Partnership credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA may increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under the Partnership credit facility bear interest at the Partnership's option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent's prime rate) plus an applicable margin. The applicable margins vary depending on the Partnership's credit rating. Upon breach by the Partnership of certain covenants governing the Partnership credit facility, amounts outstanding under the Partnership credit facility, if any, may become due and payable immediately.

As of December 31, 2014, there were $13.9 million in outstanding letters of credit and $237.0 million in outstanding borrowings under the Partnership credit facility, leaving approximately $749.1 million available for future borrowing based on the borrowing capacity of $1.0 billion.

Pricing Levels	Debt Ratings	Applicable Rate Commitment Fee	EuroDollar Rate/Letter of Credit	Base Rate +
1	A-/A3 or better	0.100%	1.000%	—%
2	BBB+/Baa1	0.125%	1.125%	0.125%
3	BBB/Baa2	0.175%	1.250%	0.250%
4	BBB-/Baa3	0.225%	1.500%	0.500%
5	BB+/Ba1	0.275%	1.625%	0.625%
6	BB/Ba2 or worse	0.350%	1.750%	0.750%

Senior Unsecured Notes. On March 7, 2014, the Partnership recorded, in the business combination, $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "2018 Notes") due on February 15, 2018. As a result of the business combination, the 2018 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $761.3 million, including a premium of $36.3 million, as of March 7, 2014.

On March 7, 2014, the Partnership recorded, in the business combination, $196.5 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December. As a result of the business combination, the 2022 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $226.0 million, including a premium of $29.5 million. On July 20, 2014, the Partnership redeemed $18.5 million aggregate principal amount of the 2022 Notes for $20.0 million, including accrued interest. On September 20, 2014, the Partnership redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest. The Partnership recorded a gain on extinguishment of debt related to the redemption of the 2022 Notes of $2.4 million for the year ended December 31, 2014.

On March 12, 2014, the Partnership commenced a tender offer to purchase any and all of the outstanding 2018 Notes. Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and on March 19, 2014, the Partnership made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, the Partnership delivered a notice of redemption for any and all outstanding 2018 Notes. All remaining outstanding 2018 Notes were redeemed on April 18, 2014 for $200.2 million, including accrued interest. The Partnership recorded a gain on extinguishment of debt related to the redemption of the 2018 Notes of $0.7 million for the year ended December 31, 2014.

On March 19, 2014, the Partnership issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400.0 million aggregate principal amount of its 2.700% senior notes due 2019 (the "2019 Notes"), $450.0 million aggregate principal amount of its 4.400% senior notes due 2024 (the "Initial 2024 Notes") and $350.0 million aggregate principal amount of its 5.600% senior notes due 2044 (the "2044 Notes"), at prices to the public of 99.850%, 99.830% and 99.925%, respectively, of their face value. The 2019 Notes mature on April 1, 2019, the 2024 Notes mature on April 1, 2024 and the 2044 Notes mature on April 1, 2044. The interest payments on the 2019 Notes, 2024 Notes and 2044 Notes are due semi-annually in arrears in April and October.

On November 12, 2014, the Partnership issued $400 million aggregate principal amount of unsecured senior notes, consisting of $100.0 million aggregate principal amount of its 4.400% senior notes due 2024 (the "Additional 2024 Notes" and together with the Initial 2024 Notes, the "2024 Notes") and $300.0 million aggregate principal amount of its 5.050% senior notes due 2045 (the "2045 Notes," and, together with the 2018 Notes, 2019 Notes, 2022 Notes, 2024 Notes and 2044 Notes, the "Senior Notes"), at prices to the public of 104.007% and 99.452%, respectively, of their face value. The Additional 2024 Notes and the Initial 2024 Notes are treated as a single class of debt securities and have identical terms, other than the issue date. The 2045 Notes mature on April 1, 2045, and the interest payments on the 2045 Notes are due semi-annually in arrears in April and October.

Prior to June 1, 2017, the Partnership may redeem all or part of the remaining 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date. On or after June 1, 2017, the Partnership may redeem all or a part of the remaining 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Prior to March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2019 Notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the 2019 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 20 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2024 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 25 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to 100% of the principal amount of the 2024 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2044 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2044 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to 100% of the principal amount of the 2044 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2044, the Partnership may redeem all or a part of the 2045 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2045 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2045 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2044, the Partnership may redeem all or a part of the 2045 Notes at a redemption price equal to 100% of the principal amount of the 2045 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability to create or incur certain liens or consolidate, merge or transfer all or substantially all of our assets.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures; and
- bankruptcy or other insolvency events involving us.

If an event of default relating to bankruptcy or other insolvency events occurs, the Senior Notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the Senior Notes may accelerate the maturity of the Senior Notes and exercise other rights and remedies.

Other Borrowings. On December 31, 2014, E2 Energy Services, LLC, one of the Ohio services companies in which the Partnership invests had certain promissory notes outstanding related to its vehicle fleet in the amount of $0.4 million due in increments through July 2017. The notes bear interest at fixed rates ranging 3.9% to 7.0%.

Credit Risk

Risks of nonpayment and nonperformance by the Partnership's customers are a major concern in it business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as its lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by the Partnership's customers could adversely affect its results of operations and reduce its ability to make distributions to its unitholders.

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry's labor and material costs remained relatively unchanged in 2012, 2013 and 2014. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and the Partnership's existing agreements, the Partnership has and will continue to pass along increased costs to its customers in the form of higher fees.

Environmental

The Partnership's operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The Partnership believes it is in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact the Partnership, see “Item 1. Business—Environmental Matters.”

Contingencies

The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

At times, the Partnership’s gas-utility and common carrier subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership’s gas-utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value, if any, of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on the Partnership’s consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to the United States District Court for the Eastern District of Louisiana. The amount of damages is unspecified. The Partnership's subsidiary, EnLink LIG, LLC, is one of the named defendants as the owner of pipelines in the area. On February 13, 2015, the court granted defendants’ joint motion to dismiss and dismissed the plaintiff’s claims with prejudice. The court’s ruling is subject to appeal. The Partnership intends to vigorously defend the case. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable.

The Partnership owns and operates a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. The Partnership also filed a claim with its insurers, which its insurers denied its claim. The Partnership disputed the denial and sued its insurers, but the Partnership has agreed to stay the matter pending resolution of its claims against Texas Brine and its insurers. In August 2014, The Partnership received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. The Partnership cannot give assurance that it will be able to fully recover its losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added a subsidiary of the Partnership, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine Company, LLC, Occidental

Chemical Corporation, and Vulcan Materials Company relating to claims arising from the Bayou Corne sinkhole. The suit is pending in the 23rd Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants have been pending since October 2012, plaintiffs are now alleging that EnLink Processing Services, LLC's negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case. The Partnership has also filed a claim for defense and indemnity with its insurers.

In October 2014, Williams Olefins, L.L.C. filed a lawsuit against a subsidiary of the Partnership, EnLink NGL Marketing, LP, in the District Court of Tulsa County, Oklahoma. The plaintiff alleges breach of contract and negligent misrepresentation relating to an ethane output contract between the parties and the subsidiary's termination of ethane production from one of its fractionation plants. The amount of damages is unspecified. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K ("Annual Report") contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Annual Report constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Annual Report, the risk factors set forth in "Item 1A. Risk Factors" may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas, NGLs and crude oil. In addition, we are also exposed to the risk of changes in interest rates on floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the CFTC to regulate certain markets for derivative products, including OTC derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement mandates in new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any future new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under three main types of contractual arrangements as summarized below. Approximately 89% of our processing margins are from fixed fee based contracts.

1.

Processing margin contracts: Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.

2. Percent of liquids contracts: Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of liquids contracts, but do decline during periods of low NGL prices.
3. Fee based contracts: Under these contracts we have no direct commodity price exposure and are paid a fixed fee per unit of volume that is processed.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our risk management committee.

We have hedged our exposure to fluctuations in prices for natural gas and NGL volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. Further, we have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon our expected equity NGL composition.

The following table sets forth certain information related to derivative instruments outstanding at December 31, 2014 mitigating the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by OPIS. The relevant index price for Natural Gas is Henry Hub Gas Daily is as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume		We Pay	We Receive *	Fair Value Asset/(Liability) (In millions)
January 2015 - December 2016	Ethane	1,168	(MBbls)	Index	$0.2873/gal	$ (4.3)
January 2015 - December 2016	Propane	1,171	(MBbls)	Index	$1.0147/gal	23.6
January 2015 - November 2015	Normal Butane	53	(MBbls)	Index	$1.1437/gal	1.0
January 2015 - November 2015	Natural Gasoline	44	(MBbls)	Index	$1.8117/gal	1.4
January 2015 - November 2015	Natural Gas	1,225	(MMBtu/d)	$4.0818/MMBtu*	Index	(0.4)
						$ 21.3

* weighted average

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

As of December 31, 2014, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were net fair value assets of $21.7 million. The aggregate effect of a hypothetical 10%, increase or decrease, in gas and NGL prices would result in a change of approximately $2.3 million in the net fair value of these contracts as of December 31, 2014.

Interest Rate Risk

The Company had no outstanding borrowings on its variable rate bank credit facility as of December 31, 2014

The Partnership is exposed to interest rate risk on its variable rate bank credit facility. At December 31, 2014, the Partnership's credit facility had $237.0 million outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $2.4 million for the year.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2022, 2024, 2044, or 2045 as these are fixed rate obligations. The estimated fair value of our senior unsecured notes was approximately $1,788.7 million as of December 31, 2014, based on market prices of similar debt at December 31, 2014. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in approximately a $157.7 million decrease in fair value of our senior unsecured notes at December 31, 2014.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-44 of this Report and are incorporated herein by reference.

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

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (December 31, 2014), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Internal Control Over Financial Reporting

See “Management's Report on Internal Control over Financial Reporting” on page F-2.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following table shows information about the executive officers and board of directors (the “Board”) of EnLink Midstream Manager, LLC, our managing member (the “Managing Member”). Executive officers serve until their successors are elected or appointed.

Name	Age	Position with the Managing Member
Barry E. Davis	53	President, Chief Executive Officer and Director
Michael J. Garberding	46	Executive Vice President and Chief Financial Officer
Steve J. Hoppe	52	Executive Vice President and President of Gas Gathering, Processing and Transmission
McMillan (Mac) Hummel	52	Executive Vice President and President of Natural Gas Liquids and Crude
Alaina Brooks	40	Senior Vice President, General Counsel and Secretary
Stan Golemon	51	Senior Vice President-Engineering and Operations
John Richels	63	Chairman of the Board
Thomas L. Mitchell	54	Director
David A. Hager	58	Director and Member of the Governance and Compensation Committee
Darryl G. Smette	67	Director
Mary P. Ricciardello**	59	Director and Member of the Audit and Conflicts Committee
James C. Crain**	66	Director and Member of the Audit Committee
Leldon E. Echols**	59	Director and Member of Audit* Committee
Rolf A. Gafvert**	61	Director and Member of the Conflicts and Governance and Compensation* Committees

*Denotes chairman of committee.
**Denotes independent director.

Barry E. Davis, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis has served as director since our initial public offering in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis also serves as a director for EnLink Midstream, LLC. Mr. Davis's leadership skills and experience in the midstream natural gas industry, among other factors, led the Board to conclude that he should serve as a director.

Michael J. Garberding, Executive Vice President and Chief Financial Officer, joined our general partner in February 2008. Mr. Garberding assumed the role of Senior Vice President and Chief Financial Officer in August 2011 and the role of Executive Vice President and Chief Financial Officer in January 2013. Mr. Garberding previously led the finance and business development organization for the Partnership. Mr. Garberding has 25 years of experience in finance and accounting. From 2002 to 2008, Mr. Garberding held various finance and business development positions at TXU Corporation, including assistant treasurer. In addition, Mr. Garberding worked at Enron North America as a Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Masters in Business Administration from the University of Michigan in 1999 and his B.B.A. in Accounting from Texas A&M University in 1991.

Steve J. Hoppe, Executive Vice President and President of Gas Gathering, Processing and Transmission, joined our general partner in March 2014. Previously, Mr. Hoppe served as Senior Vice President of Midstream Operations for Devon, which he joined in 2007. Mr. Hoppe has more than 25 years of midstream energy-industry experience, including eight years at Thunder Creek Gas Services, where he most recently served as President. Mr. Hoppe holds a Bachelor of Science degree in civil engineering from the University of Wyoming.

McMillan (Mac) Hummel, Executive Vice President and President of Natural Gas Liquids and Crude, joined our general partner in March 2014. Previously, Mr. Hummel served in various positions with The Williams Companies, which he joined in 1985, including Vice President of Commodity Services, Vice President of Natural Gas Liquids and Olefins and Vice President of Western Region Gathering and Processing. Mr. Hummel began his career with Williams serving as Director of Business Development for the Northwest Pipeline while living in Calgary, Alberta. Mr. Hummel has been a member of the American Fuel & Petrochemical Manufacturers Petrochemical Committee and the

Association of Oil Pipe Lines Pipeline Subcommittee. Mr. Hummel earned a Bachelor of Science degree in accounting and a Masters of Business Administration from the University of Utah.

Alaina K. Brooks, Senior Vice President, General Counsel and Secretary, joined our general partner in 2008. Ms. Brooks has served in several legal roles within EnLink Midstream, most recently as Deputy General Counsel before assuming the role of Senior VP, General Counsel and Secretary in September 2014. In Ms. Brooks' current role, she serves on EnLink

Midstream's Senior Leadership Team and leads the company's legal and regulatory functions. Before joining the our general partner in 2008, Ms. Brooks practiced law at Weil, Gotshal & Manges LLP and Baker Botts LLP, where she counseled clients on matters of complex commercial litigation, risk management and taxation. Ms. Brooks is a Certified Public Accountant and holds a Juris Doctor degree from Duke University School of Law and Bachelor of Science and Master of Science degrees in accounting from Oklahoma State University.

Stan Golemon, Senior Vice President—Engineering and Operations, joined our general partner in May 2008. Mr. Golemon has 25 years of experience in engineering, operations and commercial development in the midstream and exploration and production industries. From 1997 to 2008, Mr. Golemon held various midstream engineering, commercial, and management positions with Union Pacific Resources and its successor company Anadarko Petroleum Corporation including General Manager of Midstream Engineering and Engineering Supervisor. Mr. Golemon also spent 3 years with The Arrington Corporation consulting on sulfur recovery operations and Process Safety Management. Mr. Golemon began his career with ARCO Oil and Gas Company where he worked in plant engineering, onshore facilities engineering and offshore facilities engineering. Mr. Golemon graduated summa cum laude from Louisiana Tech University in 1985 with a Bachelor of Science degree in Chemical Engineering.

John Richels has been President and Chief Executive Officer of Devon since June 2010. From January 2004 to June 2010, Mr. Richels served as President of Devon. He joined the Board of Directors of Devon in 2007. Prior to 2004, Mr. Richels served as a Senior Vice President of Devon and President and Chief Executive Officer of Devon's Canadian subsidiary. Mr. Richels joined Devon through its 1998 acquisition of Canadian-based Northstar Energy Corp. Prior to joining Northstar, Mr. Richels was Managing and Chief Operating Partner of the Canadian-based national law firm, Bennett Jones. Mr. Richels has served as a director of the Managing Member and the General Partner since the completion of the business combination on March 7, 2014. Mr. Richels also currently serves on the Boards of Devon, TransCanada Corp. and BOK Financial Corporation. He holds a Bachelor of Arts degree in Economics from York University and a law degree from the University of Windsor. Mr. Richels was appointed to the Board and due to his extensive knowledge of the energy industry, including his experience with Midstream Holdings' assets and operations.

Thomas L. Mitchell has over 30 years of experience in the oil and gas industry and joined Devon as Executive Vice President and Chief Financial Officer in February 2014. Prior to Devon, Mr. Mitchell served on the board of directors and as the Executive Vice President and Chief Financial Officer of Midstates Petroleum Company throughout its initial public offering process. Prior to that, Mr. Mitchell served as Senior Vice President and Chief Financial Officer of Noble Corporation and spent 18 years with Apache Corporation in various financial and commercial roles. Mr. Mitchell has served as a director of the Managing Member and the General Partner since the completion of the business combination on March 7, 2014. He also is a Director on the Board of Hines Global REIT, Inc., a public real estate investment trust managed by Hines Interests, and holds a Bachelor of Science degree in Accounting from Bob Jones University. Mr. Mitchell was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his financial and business expertise.

David A. Hager is the Chief Operating Officer of Devon. He joined Devon in 2009 as Executive Vice President of Exploration and Production. Prior to Devon, Mr. Hager held several positions within Kerr-McGee Corp, most recently as Chief Operating Officer in the period just before its merger with Anadarko Petroleum. Mr. Hager was a Director and Chairman of the Reserves Committee on Devon's Board from 2007 until 2009 and has served as a Director for Pride International, Inc. Mr. Hager has served as a director of the Managing Member and the General Partner since the completion of the business combination on March 7, 2014. He holds a Bachelor of Science degree in Geophysics from Purdue University and a Master's in Business Administration degree from Southern Methodist University. Mr. Hager was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his business expertise.

Darryl G. Smette has been the Executive Vice President Marketing, Facilities, Pipelines and Supply Chain of Devon since 1999. Prior to joining Devon, he spent 15 years in various marketing roles with Energy Reserves Group Inc. / BHP Petroleum (Americas) Inc. He is involved with the University of Texas Department of Continuing Education as an oil and gas industry instructor. Mr. Smette is also a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. Mr. Smette has served as a director of the Managing Member and the General Partner since the completion of the business combination on March 7, 2014. He also is serving as a Director on the Board of Panhandle Oil & Gas Inc. and holds a Bachelor degree from Minot State University and a Masters in Business Administration degree from Wichita State University. Mr. Smette was selected to serve as a director due to his affiliation with Devon, his knowledge of the midstream business and his business expertise.

Mary P. Ricciardello was Senior Vice President and Chief Accounting Officer at Reliant Energy Inc., a leading independent power producer and marketer until 2002. She began her career with Reliant in 1982 and served in various financial management positions with the company including Comptroller, Senior Vice President and Chief Accounting Officer. Ms. Ricciardello has served as a director of the Managing Member and the General Partner since the completion of the business combination on March 7, 2014. Ms. Ricciardello also serves on the Board of Directors of Devon, Noble Corporation and Midstates Petroleum Company, and has served on the Board of Directors for US Concrete. Ms. Ricciardello holds a Bachelor of Science degree in Business Administration from the University of South Dakota and a Master's in Business Administration with an emphasis in Finance from the University of Houston. She is a licensed Certified Public Accountant. Ms. Ricciardello was selected to serve as a director due to her qualifications as a financial expert and her extensive experience in the energy industry, corporate finance and tax matters.

James C. Crain joined Crosstex Energy, Inc. as a director in July 2006 and has served as a director of the Managing Member since March 7, 2014. Mr. Crain retired as president of Marsh Operating Company in July 2013, where he worked since 1984 and currently is a private investor. Prior to Marsh, he was a partner at the law firm of Jenkens & Gilchrist. Mr. Crain also serves on the boards of GeoMet, Inc., and Approach Resources, Inc. Mr. Crain served as a director of the General Partner from December 2005 to August 2008. He graduated from the University of Texas at Austin with a B.B.A. degree, a master of professional accounting and a doctor of jurisprudence. Mr. Crain was selected to serve as a director due to his legal background and his experience in the oil and natural gas industry, among other factors.

Leldon E. Echols joined Crosstex Energy, Inc. as a director in January 2008 and has served as a director of the Managing Member since March 7, 2014. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of Trinity Industries, Inc. and HollyFrontier Corporation, an independent petroleum refiner and marketer. Mr. Echols brings 30 years of financial and business experience to EnLink Midstream. After 22 years with the accounting firm Arthur Andersen LLP, which included serving as managing partner of the firm's audit and business advisory practice in North Texas, Colorado and Oklahoma, Mr. Echols spent six years with Centex Corporation as executive vice president and chief financial officer. He retired from Centex Corporation in June 2006. Mr. Echols is also a member of the board of directors of Roofing Supply Group Holdings, Inc., a private company. He also served on the board of TXU Corporation where he chaired the Audit Committee and was a member of the Strategic Transactions Committee until the completion of the private equity buyout of TXU in October 2007. Mr. Echols earned a Bachelor of Science degree in accounting from Arkansas State University and is a Certified Public Accountant. He is a member of the American Institute of Certified Public Accountants and the Texas Society of CPAs. Mr. Echols has also served as a director of the General Partner since January 2008. Mr. Echols was selected to serve as a director due to his accounting and financial experience and service as the Chief Financial Officer for a public company, among other factors.

Rolf A. Gafvert was President, CEO and Director of Boardwalk GP, LLP, the General Partner of Boardwalk Pipeline Partners, LP from 2007 to 2011. Prior to that, Mr. Gafvert served as Co-President of Boardwalk GP, LLC from 2005 to 2007. Mr. Gafvert served as President of South Pipeline, which became affiliated with Boardwalk Pipeline Partners, LP in 2005, from 2000 to 2011. Mr. Gafvert was involved in Gulf South and its affiliates from 1993 to 2000, including acting as Managing Director of Koch Energy International, VP of Corporate Development for Koch Energy, Inc. and President of Gulf South. Mr. Gafvert has served as a director of the Managing Member since March 7, 2014. He holds a Master's degree in Agricultural Economics and a Bachelor of Science degree in Psychology from Iowa State University. Mr. Gafvert was selected to serve as a director due to his knowledge of the energy business and his business expertise, among other factors.

"Independent" Directors

Messrs. Crain, Echols and Gafvert and Ms. Ricciardello qualify as "independent" in accordance with the published listing requirements of The New York Stock Exchange ("NYSE"). The NYSE independence definition includes a series of objective tests, such as that the director is not an employee of the Company and has not engaged in various types of business dealings with the Company. In addition, as further required by the NYSE rules, our Board has made a subjective determination as to each independent director that no relationships exist that, in the opinion of the Board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

In addition, the members of the Audit Committee of our Board each qualify as "independent" under special standards established by the Securities and Exchange Commission ("SEC") for members of audit committees, and the Audit Committee includes at least one member who is determined by our Board to meet the qualifications of an "audit committee financial expert" in accordance with SEC rules, including that the person meets the relevant definition of an "independent" director. Mr. Echols and Ms. Ricciardello are both independent directors who have been determined to be audit committee financial experts. Unitholders should understand that this designation is a disclosure requirement of the SEC related to their experience and understanding with respect to certain accounting and auditing matters. The designation does not impose on such directors any duties, obligations or liabilities that are greater than are generally imposed on them as members of the Audit Committee and the Board, and the designation of a director as audit committee financial experts pursuant to this SEC requirement does not affect the duties, obligations or liabilities of any other member of the Audit Committee or the Board. Additionally, the Board has determined that the simultaneous service by Mr. Echols and Ms. Ricciardello on the Audit Committees of three other publicly traded companies does not impair their ability to effectively serve on the Audit Committee of the Company.

Board Committees

Our Board established three standing committees in March 2014: the Audit Committee, the Conflicts Committee and Governance and Compensation Committee. Each member of the Audit Committee is an independent director in accordance with the NYSE standards described above. Each of the Board committees has a written charter approved by the Board. Copies of such charters and the Code of Ethics and Governance Guidelines are available to any person, free of charge, on our website at www.enlink.com.

The Audit Committee of our Board is currently comprised of Mr. Echols (chair), Mr. Crain and Ms. Ricciardello. The Audit Committee assists our Board in its general oversight of our financial reporting, internal controls and audit functions, and is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors.

The Conflicts Committee of our Board is currently comprised of Messrs. Crain (chair) and Gafvert. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not directors, officers or employees of EnLink Midstream GP, LLC. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our unitholders and not a breach by our Managing Member of any duties owed to us or our unitholders.

The Governance and Compensation Committee is comprised of Messrs. Gafvert (chair) and Hager. The Governance and Compensation Committee reviews matters involving governance, including assessing the effectiveness of current policies, monitoring industry developments, and oversees certain compensation decisions as well as the compensation plans described herein.

Board Meetings and Attendance

Our Board met 6 times in 2014. All incumbent directors attended in excess of 75% of the total number of meetings of our Board and committees of our Board on which they served.

Code of Ethics

We adopted a Code of Business Conduct and Ethics (the “Code of Ethics”) applicable to all of our employees, officers, and directors, with regard to company-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. The Code of Ethics also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. A copy of the Code of Ethics is available to any person, free of charge, at our web site: www.enlink.com. If any substantive amendments are made to the Code of Ethics or if we grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our executive officers and directors, we will disclose the nature of such amendment or waiver on our web site.

Section 16(a)—Beneficial Ownership Reporting Compliance

Based on our records, except as set forth in the following, we believe that during 2014 all reporting persons complied with the Section 16(a) filing requirements applicable to them.

Item 11. Executive Compensation

We do not directly employ any of the persons responsible for managing our business. The Managing Member manages our operations and activities, and its Board and officers make decisions on our behalf. The compensation of the executive officers and directors of the Managing Member is determined by the Board upon the recommendation of its Governance and Compensation Committee. Our named executive officers also serve as executive officers of EnLink Midstream GP, LLC, our indirect wholly-owned subsidiary and the general partner of EnLink Midstream Partners, LP; therefore, the compensation of our named executive officers reflects total compensation for services both to us and the Partnership during the year ended December 31, 2014. We pay all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. We currently pay a monthly fee to EnLink Midstream GP, LLC to cover our portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to EnLink Midstream LLC, we estimate that such officers devoted the following percentage of their time to the business of EnLink Midstream Partners, LP and to EnLink Midstream, LLC, respectively, for 2014:

Executive Officer or Director	Percentage of Time Devoted to Business of EnLink Midstream Partners, LP	Percentage of Time Devoted to Business of EnLink Midstream, LLC
Barry E. Davis	80%	20%
Steve J. Hoppe	90%	10%
Mac Hummel	90%	10%
Michael J. Garberding	65%	35%
Stan Golemon	100%	—

Governance and Compensation Committee Report

The Governance and Compensation Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the Governance and Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Compensation Discussion and Analysis

The Charter of the Governance and Compensation Committee includes the following:

- The Governance and Compensation Committee has general oversight responsibility for the Company's compensation plans, policies and programs. This general oversight responsibility includes reviewing and approving compensation policies and practices for all employees, overall payroll, bonus plans, overall bonus payouts, setting bonus targets, and other general compensation matters.
- The Governance and Compensation Committee is authorized to make awards under the Company's long-term incentive plans. The Governance and Compensation Committee will review and approve the total number of awards to be made from time to time. The allocation of those awards to employees that are not "Executive Officers" (as defined below) will be made by the Chief Executive Officer.
- Not less than annually, the Governance and Compensation Committee will review the Company's executive compensation plans and policies. The Governance and Compensation Committee will review the corporate goals and objectives relevant to the compensation of the Chief Executive Officer, any officer designated as a "Section 16 Officer" and each other officer that the Governance and Compensation Committee or the Board may designate (collectively referred to as the "Executive Officers"). The Governance and Compensation Committee will evaluate the performance of the Chief Executive Officer, and, together with the Chief Executive Officer, the performance of each other Executive Officer. The Governance and Compensation Committee will at least annually review each Executive Officer's base compensation, bonus, awards under the Company's long-term incentive plans, and any other compensation, and make recommendations to the Board regarding each Executive Officer's compensation. No Executive Officer may be present during any voting or deliberations by the Governance and Compensation Committee regarding his or her compensation.
- The Governance and Compensation Committee will review the policies of the Company and the General Partner regarding the compensation of directors serving on the Board and the Board of Directors of the General Partner (the "GP Board") and make recommendations to the Board regarding such compensation, including meeting fees, committee fees and equity-based compensation.
- The Governance and Compensation Committee will review and oversee the Company's succession plans and leadership development programs for the Chief Executive Officer and the other Executive Officers, including reviewing from time to time reports and presentations regarding human resources, executive development, staffing, training, performance management, career development and other related matters as necessary.
- The Governance and Compensation Committee will review and approve the terms of any employment contracts, severance agreements, or other contracts with any Executive Officer, provided that the Board reserves to itself the

approval of the compensation of the Executive Officers.
In order to compete effectively in our industry, it is critical that we attract, retain and motivate leaders that are best positioned to deliver financial and operational results that benefit our unitholders. It is the Governance and Compensation

Committee's responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board to approve and adopt these programs.

Compensation Philosophy and Principles

Our executive compensation is designed to attract, retain and motivate top-tier executives and align their individual interests with the interests of our unitholders. The compensation of each of our executives is comprised of base salary, bonus opportunity and equity-based awards under our long-term incentive plans. The Governance and Compensation Committee's philosophy is to generally target the 50th percentile of our Peer Group (discussed below) for base salaries, target the 50th percentile of our Peer Group for bonuses (but retain discretion to reduce or increase bonus amounts to address individual performance) and to provide executives the opportunity to earn long-term compensation, in the form of equity, in the top quartile relative to our Peer Group.

The Governance and Compensation Committee considers the following principles in determining the total compensation of the named executive officers:

- in order to achieve its goals, it is critical that we attract, retain and motivate highly qualified executive officers;
- base salary and bonus opportunities must be competitive in order to attract, retain and motivate highly qualified executive officers;
- equity-based incentive compensation should represent a significant portion of the executive's total compensation in order to retain and incentivize highly qualified executives and align their individual long-term interests with the interests of unitholders;
- compensation programs must be sufficiently flexible to address special circumstances, which include payments under retention plans specifically targeted to retain highly qualified officers during challenging times; and
- the overall compensation program should drive performance and reward contributions in support of our business strategies and achievements.

Compensation Methodology

Annually, the Governance and Compensation Committee reviews our executive compensation program in total and each element of compensation specifically. The review includes an analysis of the compensation practices of other companies in our industry, the competitive market for executive talent, the evolving demands of the business, specific challenges that we may face, and individual contributions to the Company and the Partnership. The Governance and Compensation Committee recommends to the Board adjustments to the overall compensation program and to its individual components as the Governance and Compensation Committee determines necessary to achieve our goals. The Governance and Compensation Committee periodically retains consultants to assist in its review and to provide input regarding its compensation program and each of its elements.

With respect to compensation objectives and decisions regarding the named executive officers for fiscal 2014, the Governance and Compensation Committee has reviewed market data with respect to peer companies provided by Meridian Compensation Partners, LLC ("Meridian") in determining relevant compensation levels and compensation program elements for our named executive officers, including establishing their respective base salaries. In addition, Meridian has provided guidance on current industry trends and best practices to the Governance and Committee. The market data that the Governance and Committee reviewed included the base salary, bonus structure, bonus methodology and short and long-term compensation elements paid to executive officers in similar positions at our peer companies. For 2014, the Governance and Compensation Committee and Meridian collaborated to identify the following companies as "Peer Companies" of EnLink Midstream, LLC for comparison purposes: Access Midstream Partners,L.P., Boardwalk Partners, L.P., Buckeye Partners, L.P., Centerpoint Energy, Inc., Enbridge Energy Partners, L.P., EQT Corp, Hollyfrontier Corp., Magellan Midstream Partners, L.P., Markwest Energy Partners, L.P., Oneok Partners, L.P., Pembina Pipeline Corp., Regency Energy Partners, L.P., Southwestern Energy Co., Sunoco Logistics Partners, L.P., Targa Resource Partners, L.P. and Western Gas Partners, L.P. ("Peer Group"). We believe that this group of companies is representative of the industry in which we operate and the individual companies were chosen because of such companies' relative position in our industry, relative size/market capitalization, relative complexity of the business, similar organizational structure, competition for similar executive talent and the named executive officers' roles and responsibilities.

In addition, the Governance and Compensation Committee has reviewed various relevant compensation surveys with respect to determining compensation for the named executive officers. In determining the long-term incentive component of compensation of our senior executives (including the named executive officers), the Governance and Compensation Committee considers individual performance and relative equity holder benefit, the value of similar incentive awards to senior executives at comparable companies, awards made to the company's senior executives in past years, the value of all unvested awards held by the executive, and such other factors as the Governance and Compensation Committee deems relevant.

Elements of Compensation

For fiscal year 2014, the principal elements of compensation for the named executive officers were the following:

- base salary;
- annual bonus plan awards;
- long-term incentive plan awards; and
- retirement and health benefits.

The Governance and Compensation Committee reviews and makes recommendations regarding the mix of compensation, both among short- and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the named executive officers. We believe that the mix of base salary, annual bonus awards, awards under the long-term incentive plan, retirement and health benefits and perquisites and other compensation fit our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies that we require.

Base Salary. The Governance and Compensation Committee recommends base salaries for the named executive officers based on the historical salaries for services rendered to us and our affiliates, market data and responsibilities of the named executive officers. Salaries are generally determined by considering the employee's performance and prevailing levels of compensation in areas in which a particular employee works. As discussed above, except with respect to the monthly reimbursement payment that we make to EnLink Midstream GP, LLC, all of the base salaries of the named executive officers were allocated to EnLink Midstream Partners, LP as general and administration expenses. The base salaries paid to our named executive officers during fiscal year 2014 are shown in the Summary Compensation Table below. Effective January 1, 2105, the base salaries payable to our named executive officers for fiscal 2015 were established as follows: Barry E. Davis $660,000; Steve Hoppe $390,000; Mac Hummel $390,000; Michael J. Garberding $450,000; and Stan Golemon $300,000.

Bonus Awards. The Annual Bonus Plan is applicable to all employees. Prior to the changes to the Annual Bonus Plan in 2015, which implements the short-term incentive program (the "STI Program") that modifies and supersedes the Annual Bonus Plan, bonuses were awarded under the plan to our named executive officers based on a formulaic approach that utilizes a performance metric that was tied to adjusted EBITDA (see Item 6. "Selected Financial Data " for definition) as a guideline. The same adjusted EBITDA performance metric was used as a guideline for bonuses for all employees. The adjusted EBITDA goals were established at the beginning of the year by the Board upon the recommendation of the Governance and Compensation Committee. The Governance and Compensation Committee oversaw the Annual Bonus Plan and made recommendations regarding bonuses to be awarded to each of the named executive officers. Discretionary bonuses in addition to bonuses under the Annual Bonus Plan were awarded from time to time by the Governance and Compensation Committee to reward outstanding service to the company.

The final amount of bonus for each named executive officer was determined by the Governance and Compensation Committee and recommended for approval by the Board, based upon the Governance and Compensation Committee's assessment of whether such officer met his or her performance objectives established at the beginning of the performance period. These performance objectives included the quality of leadership within the named executive officer's assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer's contribution to, and enhancement of, the desired company culture. These performance objectives were reviewed and evaluated by the Governance and Compensation Committee as a whole. All of our named executive officers met or exceeded their personal performance objectives for 2014. Accordingly, the Governance and Compensation Committee and the Board awarded bonuses to the named executive officers ranging from approximately 63% to 133% of base salary for 2014. Such awards were paid in the form of equity-based awards that immediately vest and were allocated 50% in units of EnLink Midstream LLC and 50% in units of EnLink Midstream Partners, LP.

The Governance and Compensation Committee believes that a portion of executive compensation must remain discretionary and exercises its discretion with respect to bonus awards payable to its named executive officers. The Governance and Compensation Committee may exercise its discretion to reduce the amount calculated under the formula as described above, or to supplement the amount to reward or address extraordinary individual performance, challenges and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities and external competition or opportunities.

Target adjusted EBITDA was based upon a standard of reasonable market expectations and company performance, and has varied from year to year. Several factors are reviewed in determining target adjusted EBITDA, including market expectations, internal forecasts and available investment opportunities. For 2014, our adjusted EBITDA levels for bonuses were $625.0 million for minimum bonuses, $675.0 million for target bonuses and $725.0 million for maximum bonuses. The 2014 plan provided for named executive officers to receive bonus payouts of 12% to 25% of base salary at the minimum threshold, payouts ranging from 60% to 125% of base salary at the target level and payouts ranging from 90% to 188% of base salary at the maximum level.

All employees, including our named executive officers, are eligible to receive bonuses under the STI Program. The Governance and Compensation Committee and the Board will oversee the STI Program. Under the program, bonuses are awarded to employees based on a formulaic approach that utilizes certain metrics to measure success and are subject to the discretion of the Governance and Compensation Committee and the Board. The named executive officers are designated as corporate officers, gas business unit officers or liquids business unit officers for purposes of the STI Program. The metrics employed by the STI Program vary depending on the applicable officer's designation. The STI Program contemplates that (i) named executive officers designated as corporate officers will be eligible for bonuses based on our achievement level of EBITDA and safety metrics, (ii) named executive officers designated as gas business unit officers will be eligible for bonuses based on a weighted average of (x) our achievement of EBITDA and safety metrics and (y) our gas business unit's achievement of net operating income ("NOI") and safety metrics and (iii) named executive officers designated as liquids business unit officers will be eligible for bonuses based on a weighted average of (A) our achievement of EBITDA and safety metrics and (B) our liquids business unit's achievement of NOI and safety metrics. The Governance and Compensation Committee and the Board will set annual weightings used in the foregoing bonus calculations applicable to gas business unit and liquids business unit officers. In addition, the Governance and Compensation Committee and the Board, with input from management, will set annual EBITDA and NOI threshold, target and maximum goals based on a number of considerations, including reasonable market expectations, internal company forecasts, available investment opportunities and company performance. Such goals will vary from year to year. The Governance and Committee and the Board, with input from management, will also set annual safety index score threshold, target and maximum goals for each of corporate, gas business unit and liquids business unit. The goals will vary from year to year and will vary among each of corporate, gas business unit and liquids business unit. The safety index score is developed based on four categories: (i) safety statistics, including certain incident rates; (ii) leading indicators, such as safety meeting and training attendance; (iii) knowledge and development, which is based on standard assessments; and (iv) safety programs, including completed facility assessments and implementation of environmental, health and safety standards. Management of each of the gas and liquids business unit will participate in setting specific goals within the foregoing categories to ensure that the safety program influences and incents desired outcomes.

The Board, based on recommendations of the Governance and Compensation Committee, will determine final bonus amounts for our named executive officers. As with our prior annual bonus plans, the Governance and Compensation Committee believes that a portion of executive compensation must remain discretionary and subject to the discretion of the Governance and Compensation Committee and the Board with respect to bonus awards payable to its named executive officers. Therefore, the STI Program contemplates that the Governance and Compensation Committee and the Board retain discretion with respect to bonus awards payable to named executive officers. The Governance and Compensation Committee may exercise its discretion to reduce the amount calculated under the formulas as described above, or to supplement the amount to reward or address extraordinary individual performance, challenges and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities, and external competition or opportunities.

Additionally, on January 14, 2014, the GP Board, upon the recommendation of its compensation committee (the "GP Committee"), approved and authorized the Partnership to fund a cash bonus plan in an aggregate amount of up to $10.0 million (the "Transaction Bonus Plan") to reward a broad base of employees, including the then-existing named executive officers of the Partnership, upon closing of the transactions with Devon. In February 2014, the GP Committee awarded $1,600,000 to Barry E. Davis under the Transaction Bonus Plan, and the GP Committee and the GP Board approved allocations to the other then-existing named executive officers of the Partnership, including the following amounts: Michael J. Garberding $800,000 and Stan Golemon $200,000.

Long-Term Incentive Plans. We believe that equity awards are instrumental in attracting, retaining, and motivating employees, and that they align the interests of our officers and directors with the interests of the unitholders. In connection with the business combination, the EnLink Midstream, LLC 2014 Long-Term Incentive Plan was adopted, effective as of February 5, 2014 (the "2014 Plan"). Additionally, effective as of the consummation of the business combination, we assumed the EnLink Midstream, LLC 2009 Long-Term Incentive Plan (formerly known as the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan) (the “2009 Plan”) in respect of the outstanding awards granted thereunder and the award agreements governing such awards, in each case subject to applicable adjustments in the manner set forth in the Merger Agreement. Our directors and officers also are eligible to participate in the EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”).

The Board, at the recommendation of the Governance and Compensation Committee, approves the grants of awards to our named executive officers. The Governance and Compensation Committee believes that equity compensation should comprise a significant portion of a named executive officer’s compensation, and considers a number of factors when determining the grants to each individual. The considerations include: the general goal of allowing the named executive officer the opportunity to earn aggregate equity compensation (comprised of our units and Partnership units) in the upper quartile of our Peer Group; the amount of unvested equity held by the individual executive; the executive's performance; and other factors as determined by the Governance and Compensation Committee.

A discussion of each plan follows:

EnLink Midstream, LLC 2014 Long-Term Incentive Plan. Employees, non-employee directors and other individuals who provide services to us or our affiliates may be eligible to receive awards under the 2014 Plan; however, the Governance and Compensation Committee has the sole discretion to determine which eligible individuals receive awards under the 2014 Plan, subject to the Board's review of awards to certain of our executive officers. The 2014 Plan is administered by the Governance and Compensation Committee and permits the grant of cash and equity-based awards, which may be awarded in the form of options, restricted unit awards, restricted incentive units, unit appreciation rights ("UARs"), distribution equivalent rights ("DERs"), unit awards, cash awards and performance awards. At the time of adoption of the 2014 Plan, 11,000,000 common units representing limited liability company interests in us were initially reserved for issuance pursuant to awards under the 2014 Plan. Common units subject to an award under the 2014 Plan that are canceled, forfeited, exchanged, settled in cash or otherwise terminated, including withheld to satisfy exercise prices or tax withholding obligations, will again become available for delivery pursuant to other awards under the 2014 Plan. Of the 11,000,000 common units that may be awarded under the 2014 Plan, 10,324,211 common units remain eligible for future grants by the Managing Member as of December 31, 2014. The long-term compensation structure is intended to align the employee's performance with long-term performance for our unitholders.

The 2014 Plan will automatically expire on the tenth anniversary of its effective date. The Board may amend or terminate the 2014 Plan at any time, subject to any requirement of unitholder approval required by applicable law, rule or regulation. The Governance and Compensation Committee may generally amend the terms of any outstanding award under the 2014 Plan at any time. However, no action may be taken by the Board or the Governance and Compensation Committee under the 2014 Plan that would materially and adversely affect the rights of a participant under a previously granted award without the participant's consent.

- Options. Options are rights to purchase a specified number of our common units at a specified price. The exercise price of an option cannot be less than the fair market value per common unit on the date on which the option is granted and the term of the option cannot exceed ten years from the date of grant. Options will be exercisable on such terms as the Governance and Compensation Committee determines. The Governance and Compensation Committee will also determine the time or times at which, and the circumstances under which, an option may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, form of consideration payable in settlement, method by or forms in which common units will be delivered to participants, and whether or not an option will be in tandem with a UAR award. Under no circumstances will distributions or DERs be granted or made with respect to option awards. An option granted to an employee may consist of an option that complies with the requirements of Section 422 of the Internal Revenue Code, referred to in the 2014 Plan as an "incentive unit option." In the case of an incentive unit option granted to an employee who owns (or is deemed to own) more than 10% of the total combined voting power of all classes of units, the exercise price of the option must be at least 110% of the fair market value per common unit on the date of grant and the term of the option cannot exceed five years from the date of grant.

- Unit Appreciation Rights or UARs. A UAR is a right to receive an amount equal to the excess of the fair market value of one common unit on the date of exercise over the grant price of the UAR. UARs will be exercisable on such terms as the Governance and Compensation Committee determines. The Governance and Compensation Committee will also determine the time or times at which and the circumstances under which a UAR may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, method of settlement, form of consideration payable in settlement, method by or forms in which common units will be delivered or deemed to be delivered to participants, whether or not a UAR will be in tandem with an option award, and any other terms and conditions of any UAR. UARs may be either freestanding or in tandem with other awards. Under no circumstances will distributions or DERs be granted or made with respect to UAR awards.

Restricted Units. A restricted unit is a grant of a common unit subject to a substantial risk of forfeiture, restrictions on transferability and any other restrictions determined by the Governance and Compensation Committee. The Governance and Compensation Committee may provide, in its discretion, that the distributions made by us with respect to the restricted units will be subject to the same forfeiture and other restrictions as the restricted unit and, if so restricted, such distributions will be held, without interest, until the restricted unit vests or is forfeited with the unit distribution right being paid or forfeited at the same time, as the case may be. In addition, the Governance and Compensation Committee may provide that such distributions be used to acquire additional restricted units for the participant. Under no circumstances will DERs be granted or made with respect to restricted unit awards.

- Restricted Incentive Units. Restricted incentive units are rights to receive cash, common units or a combination of cash and common units at the end of a specified period. Restricted incentive units may be subject to restrictions, including a risk of forfeiture, as determined by the Governance and Compensation Committee. The Governance and Compensation Committee may, in its sole discretion, grant DERs with respect to restricted incentive units.

- Distribution Equivalent Rights or DERs. DERs entitle a participant to receive cash or additional awards equal to the amount of any cash distributions made by us with respect to a common unit during the period the right is outstanding. DERs may be granted as a stand-alone award or with respect to awards other than restricted units, options or UARs. Subject to Section 409A of the Internal Revenue Code, payment of a DER issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the Governance and Compensation Committee.

- Unit Awards. The 2014 Plan permits the grant of unit awards, which are common units that are not subject to vesting restrictions.

- Cash Awards. The 2014 Plan permits the grant of cash awards, which are awards denominated and payable in cash.

- Performance Awards. Performance awards represent a participant’s right to receive an amount of cash, common units, or a combination of both, contingent upon the annual attainment of specified performance measures within a specified period. The Governance and Compensation Committee or other committee that is intended to satisfy the requirements of Section 162(m) of the Internal Revenue Code (the “Section 162(m) Committee”), as applicable, will determine the applicable performance period, the performance goals and such other conditions that apply to each performance award. In addition, the 2014 Plan permits, but does not require, the Governance and Compensation Committee or the Section 162(m) Committee, as applicable, to structure any performance award made to a covered employee as qualified performance-based compensation under Section 162(m) of the Internal Revenue Code. Section 162(m) of the Internal Revenue Code generally limits the deductibility for federal income tax purposes of annual compensation paid to certain top executives of a company to $1 million per covered employee in a taxable year (to the extent such compensation does not constitute qualified performance-based compensation under Section 162(m) of the Internal Revenue Code). Prior to the payment of any compensation based on the achievement of performance goals applicable to performance awards that are intended to provide qualified performance-based compensation under Section 162(m) of the Internal Revenue Code, the Governance and Compensation Committee or the Section 162(m) Committee, as applicable, must certify in writing that applicable performance goals and any of the material terms thereof were, in fact, satisfied.

Upon a change of control of the Company and except as provided in the award agreement, the Governance and Compensation Committee may cause unit options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control of the Company and except as provided in the award agreement, the Governance and Compensation Committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement or the other terms of such awards.

EnLink Midstream 2009 Long-Term Incentive Plan. The 2009 Plan provides for the award of unit options, restricted units, restricted incentive units and other awards (collectively, “Awards”). As a result of the consummation of the business combination, however, it is anticipated that no future Awards will be granted under the 2009 Plan. The Governance and Compensation Committee administers the 2009 Plan and has the authority to grant waivers of the applicable plan terms, conditions, restrictions and limitations. As of December 31, 2014, no common units are reserved for issuance under the 2009 Plan. Each outstanding unit award under the 2009 Plan has a vesting period that was established in the sole discretion of the Governance and Compensation Committee and as modified by the waivers entered into by certain individuals in connection with the business combination, provided that earlier vesting

may arise by reason of death, disability, retirement or otherwise.
The Governance and Compensation Committee may amend, modify, suspend or terminate the 2009 Plan, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring unitholder approval under any applicable legal requirements will be effective until such approval has been obtained.

EnLink Midstream GP, LLC Long-Term Incentive Plan. EnLink Midstream GP, LLC has adopted the GP Plan for employees, consultants and independent contractors of EnLink Midstream GP, LLC and its affiliates and outside directors of the GP Board who perform services for the Partnership. The GP Plan is administered by the GP Committee and permits the grant of awards, which may be awarded in the form of restricted incentive units or unit options. An aggregate of 9,070,000 common units representing limited partner interests in the Partnership are authorized for issuance under the GP Plan. Of the 9,070,000 common units that may be awarded under the GP Plan, 2,991,787 common units remain eligible for future grants as of December 31, 2014. The long-term compensation structure is intended to align the employee's performance with long-term performance for the Partnership's unitholders. The GP Plan will automatically expire on the tenth anniversary of the date (May 9, 2013) of the GP Plan's last approval by unitholders of the Partnership. The GP Board, in its discretion, may terminate or amend the GP Plan at any time with respect to any units for which a grant has not yet been made. The GP Board also has the right to alter or amend the GP Plan or any part of the GP Plan from time to time, including increasing the number of units that may be granted subject to the approval requirements of the exchange upon which the common units are listed at that time. The GP Committee may generally amend the terms of any outstanding award under the GP Plan at any time. However, no action may be taken by the GP Board or the GP Committee under the GP Plan that would materially reduce the benefits of a participant under a previously granted award without the consent of the participant.

- Unit Options. The GP Plan currently permits the grant of options covering common units. These are rights to purchase a specified number of common units of the Partnership at a specified price. All unit option grants will have an exercise price that is not less than 100% the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the GP Committee and the term of the options cannot exceed ten years from the date of grant. In addition, unit options may, pursuant to their terms, become exercisable upon a change of control of the Partnership or the General Partner. The General Partner will be entitled to reimbursement by the Partnership for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by the Partnership. If the Partnership issues new common units upon exercise of the unit options, the total number of common units outstanding will increase, and the General Partner will pay the Partnership the proceeds it received from the optionee upon exercise of the unit option. Any unit options granted pursuant to the GP Plan have been designed to furnish additional compensation to employees, consultants, independent contractors and directors and to align their economic interests with those of common unitholders.

- Restricted Incentive Units. The GP Plan currently permits the grant of restricted incentive units. These awards of restricted incentive units are rights that entitle the grantee to receive common units of the Partnership upon the vesting of such restricted incentive units. The GP Committee will determine the terms, conditions and limitations applicable to any awards of restricted incentive units. Awards of restricted incentive units will have a vesting period established in the sole discretion of the GP Committee, which may include, without limitation, vesting upon the achievement of specified performance goals. In addition, the restricted incentive units may, pursuant to their terms, vest upon a change of control of the Partnership or the General Partner. Common units to be delivered upon the vesting of restricted incentive units may be common units acquired by the General Partner in the open market, common units already owned the General Partner, common units acquired by the General Partner directly from us or any other person or any combination of the foregoing. The General Partner will be entitled to reimbursement by the Partnership for the cost incurred in acquiring common units. If the Partnership issues new common units upon vesting of the restricted incentive units, the total number of common units outstanding will increase. The GP Committee, in its discretion, may grant tandem DERs with respect to restricted incentive units which entitles a participant to receive cash or additional awards equal to the amount of any cash distributions made by us with respect to a common unit during the period the right is outstanding. The GP Committee may provide, in its discretion, that the DERs will be subject to the same forfeiture and other restrictions as a restricted incentive unit and, if so restricted, such distributions will be held, without interest, until the restricted incentive unit vests or is forfeited with the distribution being paid or forfeited at the same time, as the case may be. The Partnership intends for the issuance of the common units upon vesting of the restricted incentive units under the GP Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units.

Therefore, under current policy, GP Plan participants will not pay any consideration for the common units they receive, and the Partnership will receive no remuneration for the units.

The total value of the equity compensation granted to our executive officers generally has been awarded 50% in restricted incentive units of the Partnership and 50% in restricted incentive units of EnLink Midstream, LLC. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. In addition, for fiscal year 2014, EnLink Midstream, LLC granted 88,788, 34,153, 27,322, 44,090 and 28,436 restricted incentive units to Barry

E. Davis, Steve J. Hoppe, Mac Hummel, Michael J. Garberding and Stan Golemon, respectively. For fiscal year 2014, EnLink Midstream GP, LLC granted 102,752, 39,708, 35,967, 51,042 and 27,473 restricted incentive units to Barry E. Davis, Steve J. Hoppe, Mac Hummel, Michael J. Garberding and Stan Golemon, respectively. All performance and restricted incentive units that we grant are charged against earnings according to FASB Accounting Standards Codification 718—"Compensation—Stock Compensation" (ASC 718).

Retirement and Health Benefits. We offer a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as our other employees. We maintain a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2014, we matched 100% of every dollar contributed for contributions of up to 6% of salary (not to exceed the maximum amount permitted by law) made by eligible participants. A portion of the retirement benefits provided to the named executive officers were allocated to us as general and administration expenses. Our executive officers are also eligible to participate in any additional retirement and health benefits available to our other employees.

Perquisites. We do not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax and related expenses for membership in an industry related private lunch club (totaling less than $2,500 per year per person).

Change in Control and Severance Agreements

All of our named executive officers and certain members of senior management entered into change in control agreements (the "Change in Control Agreements") and severance agreements (the "Severance Agreements" and collectively with the Change in Control Agreements, the "Agreements") with the Operating Partnership as of November 1, 2014.

The Agreements restrict the officers from competing with the Operating Partnership, EnLink Midstream, LLC, the Partnership, our general partner, its manager or their respective affiliates and subsidiaries (the "Company Group") during the term of employment. In addition, the Agreements restrict the officers, both during their employment and for varying periods following the termination of such employment, from (i) disclosing confidential information, (ii) soliciting other employees to accept employment with a third party or terminate their employment with any member of the Company Group, (iii) soliciting or interfering with any person that is or was a client or customer of any member of the Company Group and (iv) disparaging any member of the Company Group. The Agreements provide the Operating Partnership with equitable remedies and with the right to clawback benefits if the restrictions described in this paragraph are breached by a terminated employee following a termination date. In the event of a termination, the terminated employee is required to execute a general release of the Company Group in order to receive any benefits under the Agreements.

Under the Severance Agreements, if an officer's employment is terminated without cause (as defined in the Severance Agreement) or is terminated by the officer for good reason (as defined in the Severance Agreement), such officer will be entitled to receive (i) his or her accrued base salary up to the date of termination, (ii) any unpaid annual bonus with respect to the calendar year ending prior to the officer's termination date that has been earned as of such date, (iii) a prorated amount of the bonus (to the extent such bonus would have otherwise been earned by such officer) for the calendar year in which the termination occurs, (iv) such other fringe benefits (other than any bonus, severance pay benefit or medical insurance benefit) normally provided to employees that are already earned or accrued as of the date of termination (the foregoing items in clauses (i) - (iv) are referred to as the "General Benefits"), (v) certain outplacement services (the "Outplacement Benefits"), (vi) a lump sum severance equal to the sum of (A) the officer's then-current base salary and (B) any target bonus (as defined in the applicable Agreement) for the year that includes the date of termination (the "Severance Benefit") times two for the officers plus (vii) an amount equal to the cost to the officer to extend his or her then-current medical insurance benefits for 18 months following the effective date of the termination (the "Medical Severance Benefit").

Potential Payments Upon a Change of Control

Under the Change in Control Agreements, if, within 120 days prior to or within 24 months following a change in control (as defined in the Change in Control Agreement), an officer's employment is terminated without cause (as defined in the Change in Control Agreement) or is terminated by the officer for good reason (as defined in the Change in Control Agreement), such officer will be entitled to the General Benefits, the Outplacement Benefits, the Medical

Severance Benefit and the Severance Benefit; provided, however, that the Chief Executive Officer would be entitled to three times the Severance Benefit and the other officers would be entitled to two times the Severance Benefit. Other members of senior management (including Stan Golemon and Alaina K. Brooks) do not receive an increase in the Severance Benefit if they are terminated in connection with a change in control.

In addition, the Agreements provide for the General Benefits upon the officer’s termination of employment due to his or her death or disability (as defined in the Agreements).

The Agreements provide that an officer may only become entitled to payments under the Severance Agreement or the Change in Control Agreement, but not under both Agreements. Upon execution of an Agreement, such Agreement will continue in effect until the applicable renewal date, the termination of the officer’s employment or termination of the

Agreement by the Operating Partnership, except that the Change in Control Agreement may not be terminated for a period that begins 120 days prior to, and ends 24 months following, a change in control.

If the payments and benefits provided to an officer under the Agreements (i) constitute a “parachute payment” as defined in Section 280G of the Internal Revenue Code and exceed three times the officer’s “base amount” as defined under Section 280G(b)(3) of the Internal Revenue Code, and (ii) would be subject to the excise tax imposed by Section 4999 of the Internal Revenue Code, then the officer’s payments and benefits will be either (A) paid in full, or (B) reduced and payable only as to the maximum amount which would result in no portion of such payments and benefits being subject to such excise tax , whichever results in the receipt by the officer on an after-tax basis of the greatest amount (taking into account the applicable federal, state and local income taxes, the excise tax imposed by Section 4999 of the Internal Revenue Code and all other taxes, including any interest and penalties, payable by the officer).

With respect to the long-term incentive plans, the amounts to be received by our named executive officers in the event of a change of control (as defined in the long-term incentive plans) will be automatically determined based on the number of units or shares of common stock underlying any unvested equity incentive awards held by a named executive officer at the time of a change of control. The terms of the long-term incentive plans were determined based on past practice and the applicable compensation committee's understanding of similar plans utilized by public companies generally at the time we adopted such plans. The determination of the reasonable consequences of a change of control is periodically reviewed by the applicable compensation committee.

Upon a change of control, and except as provided in the award agreement, the applicable compensation committee may cause unit options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control and except as provided in the award agreement, the applicable compensation committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement or the other terms of such awards.

The potential payments that may be made to the named executive officers upon a termination of their employment or in connection with a change of control as of December 31, 2014 are set forth in the table in the section below entitled Payments Upon Termination or Change in Control.

Role of Executive Officers in Executive Compensation

The Board, upon recommendation of the Governance and Compensation Committee, determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Governance and Compensation Committee. Barry E. Davis, the Chief Executive Officer, reviews his recommendations regarding the compensation of his leadership team with the Governance and Compensation Committee, including specific recommendations for each element of compensation for the named executive officers. Barry E. Davis does not make any recommendations regarding his personal compensation.

Tax and Accounting Considerations

Our equity compensation grant policies have been impacted by the implementation of FASB ASC 718, which we adopted effective January 1, 2006. Under this accounting pronouncement, we are required to value unvested unit options granted prior to our adoption of FASB ASC 718 under the fair value method and expense those amounts in the income statement over the unit options' remaining vesting period. As a result, we currently intend to discontinue grants of unit option awards and instead grant restricted unit and restricted incentive unit awards to the named executive officers and other employees. We have structured the compensation program to comply with Section 409A of the Internal Revenue Code. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. In 2014, Barry E. Davis had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Section 162(m) of the Internal Revenue Code.

Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Restricted Unit and Restricted Incentive Unit Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($) (3)	Change in Pension value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)		Total ($)
Barry E. Davis	2014	587,885	800,000	6,000,000	—	1,600,000	—	683,607	(4)	9,671,492
President and Chief	2013	525,000	492,188	1,609,522	—	—	—	266,774		2,893,484
Executive Officer	2012	500,000	406,250	1,333,787	—	—	—	257,496		2,497,533
Steve J. Hoppe	2014	304,327	350,000	2,500,000	—	—	—	93,832	(5)	3,248,159
Executive Vice President and										—
President of Gathering										—
McMillan (“Mac”) Hummel	2014	325,569	350,000	2,131,596	—	—	—	84,625	(6)	2,891,790
Executive Vice President and										—
President of Natural Gas Liquids and Crude										—
Michael J. Garberding	2014	391,923	500,000	3,000,000	—	800,000	—	480,884	(7)	5,172,807
Executive Vice	2013	350,000	224,100	1,465,519	—	—	—	164,596		2,204,215
President and Chief Financial Officer	2012	290,000	141,375	640,212	—	—	—	138,874		1,210,461
Stan Golemon	2014	298,269	190,000	1,779,436	—	200,000	—	130,335	(8)	2,598,040
Senior Vice President	2013	285,000	128,250	536,512	—	—	—	102,847		1,052,609
	2012	275,000	89,375	533,515	—	—	—	99,281		997,171

(1) Bonuses include all payments made under the Annual Bonus Plan. For 2014, 2013 and 2012, the named executive officers received bonuses in the form of equity awards that immediately vest. The amounts shown for 2014, 2013

and 2012 represent the grant date fair value of awards computed in accordance with FASB ASC 718. Such awards were allocated 50% in restricted units or restricted incentive units of EnLink Midstream, LLC and 50% in restricted units or restricted incentive units of EnLink Midstream Partners, LP See “Bonus Awards” above.

(2) The amounts shown represent the grant date fair value of awards computed in accordance with FASB ASC 718. See Note 9 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards.

(3) Non-Equity Incentive Plan Compensation includes payments made under the cash bonus plan funded by EnLink Midstream Partners, LP in January 2014, which was designed to reward a broad base of employees for successful consummation of the transactions with Devon. These amounts were awarded in February 2014.

(4) Amount of all other compensation for Mr. Barry Davis includes professional organization and social club dues, a matching 401(k) contribution of $15,600, distributions or dividends on restricted units and restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $144,228 in 2014, distributions on restricted units or restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount $251,576 in 2014 and a $258,968 cash award for Mr. Davis’ waiver of certain rights with respect to the acceleration and vesting of awards under applicable long-term incentive plans in connection with the consummation of the business combination with Devon.

(5) Amount of all other compensation for Mr. Steve Hoppe includes professional organization and social club dues, a matching 401(k) contribution of $15,600, distributions on restricted units and restricted incentive units and performance units of EnLink Midstream, LLC in the amount of $21,516 in 2014 and distributions on restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount of $43,480 in 2014.

(6) Amount of all other compensation for Mr. Mac Hummel includes professional organization and social club dues, a matching 401(k) contribution of $14,792, distributions on restricted units and restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $17,213 in 2014 and distributions on restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount of $39,384 in 2014.

(7) Amount of all other compensation for Mr. Michael Garberding includes professional organization and social club dues, a matching 401(k) contribution of $15,600, distributions or dividends on restricted units or restricted incentive units of EnLink Midstream, LLC in the amount of $93,893 in 2014, distributions on restricted units or restricted incentive units of EnLink Midstream Partners, LP in the amount of $161,212 in 2014 and a $196,944 cash award for Mr. Garberding’s waiver of certain rights with respect to the acceleration and vesting of awards under applicable long-term incentive plans in connection with the consummation of the business combination with Devon.

(8) Amount of all other compensation for Mr. Stan Golemon includes a matching 401(k) contribution of $15,600, dividends or distributions on restricted units or restricted incentive units of EnLink Midstream, LLC in the amount of $38,522 in 2014 and distributions on restricted units or restricted incentive units of EnLink Midstream Partners, LP in the amount of $62,977 in 2014.

Grants of Plan-Based Awards for Fiscal Year 2014 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2014 by EnLink Midstream, LLC and EnLink Midstream GP, LLC, including awards made under their applicable long-term incentive plans.

ENLINK MIDSTREAM, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Number of Shares		Grant Date Fair Value of Shares Awards
Barry E. Davis	3/14/2014	6,821	(1)	$246,102
	4/1/2014	81,967	(2)	$2,999,992
Steve J. Hoppe	4/1/2014	34,153	(2)	$1,250,000
Mac Hummel	4/1/2014	27,322	(2)	$999,985
Michael J. Garberding	3/14/2014	3,106	(1)	$112,064
	4/1/2014	40,984	(2)	$1,500,014
	3/14/2014	12,998	(3)	$475,727
Stan Golemon	3/14/2014	1,777	(1)	$64,114
	4/1/2014	13,661	(2)	$499,993

(1) These grants vested on March 14, 2014.

(2) These grants include right to receive dividends or DERs on restricted units or restricted incentive units, as applicable, if made on unrestricted common units during the restricted period unless otherwise forfeited and vest 100% on March 7, 2017.

(3) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on March 7, 2016.

ENLINK MIDSTREAM GP, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Number of Units		Grant Date Fair Value of Unit Awards
Barry E. Davis	3/14/2014	7,453	(1)	$246,098
	4/1/2014	95,299	(2)	$3,000,013
Steve J. Hoppe	4/1/2014	39,708	(2)	$1,250,008
Mac Hummel	4/1/2014	31,766	(2)	$999,994
	7/7/2014	4,201	(2)	$131,617
Michael J. Garberding	3/14/2014	3,393	(1)	$112,037
	4/1/2014	47,649	(2)	$1,499,991
	3/14/2014	9,648	(3)	$303,719
Stan Golemon	3/14/2014	1,942	(1)	$64,125
	4/1/2014	15,883	(2)	$499,997

(1) These grants vested on March 14, 2014.

(2) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on March 7, 2017.

(3) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on March 7, 2016.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2014

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2014, including, but not limited to, awards made under the EnLink Midstream GP, LLC Long-Term Incentive Plan and the EnLink Midstream, LLC Long-Term Incentive Plans.

ENLINK MIDSTREAM, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards					Stock Awards				
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number or Units That Have Not Vested (#)		Market Value of Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	50,080	(1)	1,780,845	—	—
						52,301	(3)	1,859,824		
						81,967	(4)	2,914,747		
Steve J. Hoppe	—	—	—	—	—	34,153	(4)	1,214,481	—	—
Mac Hummel	—	—	—	—	—	27,322	(4)	971,570		
Michael J. Garberding	—	—	—	—	—	24,038	(1)	854,791	—	—
						31,381	(3)	1,115,908		
						12,267	(5)	436,215		
						40,984	(4)	1,457,391		
Stan Golemon	—	—	—	—	—	4,630	(6)	164,643	—	