American Midstream Partners, LP
Form 10-K
March 10, 2015

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

FORM 10-K

x 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: 001-35257

AMERICAN MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware<br>(State or other jurisdiction of incorporation or organization) | 27-0855785<br>(I.R.S. Employer Identification No.) |
| 1400 16th Street, Suite 310<br>Denver, CO<br>(Address of principal executive offices) | 80202<br>(Zip code) |

(720) 457-6060
(Registrant's telephone number, including area code)

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

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Units Representing Limited Partnership Interests | New York Stock Exchange |

Securities registered pursuant to section 12(g) of the Act:
None

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

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

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

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

| | | | | |
|---|---|---|---|---|
| Large accelerated filer | o | | Accelerated filer | x |
| Non-accelerated filer | o | (Do not check if a smaller reporting company) | Smaller reporting company | o |

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2014, was $294,650,782. The aggregate market value was computed by reference to the last sale price of the registrant's common units on the New York Stock Exchange on June 30, 2014.

There were 22,753,974 common units, 5,909,349 Series A Units and 1,277,772 Series B Units of American Midstream Partners, LP outstanding as of March 6, 2015. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

Documents Incorporated by Reference

None.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. These risks and uncertainties, many of which are beyond our control, include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" as well as the following risks and uncertainties:

- our ability to access capital to fund growth including access to the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety, regulation of over-the-counter derivatives market and entities, and protection of the environment;
- the timing and extent of changes in crude oil, natural gas, natural gas liquids and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around our assets and our success in connecting crude oil and natural gas supplies to our gathering and processing systems;
- the demand for NGL products by the petrochemical, refining or other industries;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects and the successful integration and future performance of such assets;
- our ability to hire as well as retain qualified personnel to execute our business strategy;
- volatility in the price of our common units;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- our ability to timely and successfully integrate our current and future acquisitions, including the realization of all anticipated benefits of any such transaction, which otherwise could negatively impact our future financial performance; and
- general economic, market and business conditions.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Annual Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in "Item 1A. Risk Factors" in this Annual Report on Form 10-K (the "Annual Report"). Statements in this report speak as of the date of this report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

## GLOSSARY OF TERMS

As generally used in the energy industry and in this Annual Report on Form 10-K (the "Annual Report"), the identified terms have the following meanings:

| | |
|---|---|
| Bbl | Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit. |
| Bbl/d | Barrels per day. |
| Bcf | Billion cubic feet. |
| Btu | British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. |
| Condensate | Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing. |
| /d | Per day. |
| FERC | Federal Energy Regulatory Commission. |
| Fractionation | Process by which natural gas liquids are separated into individual components. |
| Gal | Gallons. |
| MBbl | Thousand barrels. |
| MMBbl | Million barrels. |
| MMBbl/d | Million barrels per day. |
| MMBtu | Million British thermal units. |
| Mcf | Thousand cubic feet. |
| MMcf | Million cubic feet. |
| NGL or NGLs | Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature. |
| Tcf | Trillion cubic feet. |
| Throughput | The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period. |

As used in this Annual Report, unless the context otherwise requires, "we," "us," "our," the "Partnership" and similar terms refer to American Midstream Partners LP, together with its consolidated subsidiaries.

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PART I
Item 1. Business

Overview

American Midstream Partners, LP (along with its consolidated subsidiaries, "we," "us," "our," or the "Partnership") is a growth-oriented Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We are engaged in the business of gathering, treating, processing, and transporting natural gas, fractionating NGLs and storing specialty chemical products through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, three interstate pipelines, five intrastate pipelines and four marine terminal sites. We also own a 66.7% non-operating interest in Main Pass Oil Gathering, LP ("MPOG"), a crude oil gathering and processing system, as well as a 50% undivided, non-operating interest in the Burns Point Plant, a natural gas processing plant. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, North Dakota, Tennessee and Texas, provide critical infrastructure that links producers of natural gas, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. We currently operate more than 3,000 miles of pipelines that gather and transport over 1 Bcf/d of natural gas and operate approximately 1.7 million barrels of storage capacity across four marine terminal sites.

Our operations are organized into three segments: i) Gathering and Processing, ii) Transmission and iii) Terminals. In our Gathering and Processing segment, we receive fee-based and fixed-margin compensation for gathering, processing, transporting and treating natural gas. Where we provide processing services at the plants that we own or share an interest, or obtain processing services for our own account under our elective processing arrangements, we typically retain and sell a percentage of the residue natural gas and/or resulting NGLs under percent of proceeds ("POP") arrangements.

In our Transmission segment, we receive fee-based and fixed-margin compensation primarily related to capacity reservation charges under our firm transportation contracts and the transportation of natural gas pursuant to our interruptible transportation and fixed-margin contracts.

In our Terminals segment, we generally receive fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services provided to our customers, such as excess throughput, steam heating, truck weighing, etc. The terms of our storage-leasing contracts are multiple years, with renewal options.

Recent Developments

On October 14, 2014, we acquired 100% of the membership interests of Costar Midstream, L.L.C. ("Costar Midstream") from Energy Spectrum Partners VI LP ("Energy Spectrum") and Costar Midstream Energy, LLC ("Costar Midstream Energy") in exchange for $265.4 million in cash and 6.9 million of the Partnership's limited partner common units. Costar Midstream is an onshore gathering and processing company with its primary gathering, processing, fractionation, and off-spec condensate treating and stabilization assets in East Texas and the Permian basin, with a significant crude oil gathering system project underway in the Bakken oil play. The acquisition was funded with approximately 6.9 million common units issued directly to Energy Spectrum and Costar Midstream Energy, which are subject to certain lock-up provisions, and $265.4 million of cash from borrowings under our revolving credit facility and proceeds from our August 2014 private placement of common units.

On August 11, 2014, we acquired a 66.7% non-operated interest in Main Pass Oil Gathering, LP ("MPOG") which is an offshore oil gathering system, for a net purchase price of $12.0 million. The acquisition was financed through borrowings under our revolving credit facility.

On January 31, 2014, we acquired approximately 120 miles of high- and low-pressure pipelines ranging from 4 to 8 inches in diameter with over 9,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas (the "Lavaca System") along with the right to construct additional midstream infrastructure to service dedicated acreage. The consideration for the Lavaca System was financed with the net proceeds of our January equity offering and the issuance to our General Partner of 1,168,225 Series B Units (the "Series B Units") representing series B limited partnership interests in the Partnership.

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $107.26 per barrel to a low of $44.45 per barrel from January 1, 2014 through March 5, 2015. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $6.15 per MMBtu to a low of $2.58 per MMBtu from January 1, 2014 through March 5, 2015. We are unable to predict future movements in the market price for natural gas, oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. For the year ended December 31, 2014, net loss attributable to the Partnership was $98.0 million, primarily as a result of impairments of property, plant and equipment of $99.9 million, compared to net loss attributable to the Partnership of $34.0 million for the year ended December 31, 2013. If commodity prices continue to trend lower as they did in the latter part of 2014 and early 2015, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants in our revolving credit facility. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

Business Strategies

Our principal business objective is to strategically grow the partnership in order to increase the quarterly cash distributions that we pay to our unitholders while ensuring the long-term stability of our business. We expect to achieve this objective by executing the following strategies:

Pursue Strategic and Accretive Acquisitions, Including Acquisitions from High Point Infrastructure Partners, LLC ("HPIP") and Its Affiliates in Drop Down Transactions. We plan to pursue accretive acquisitions of energy infrastructure assets, including in drop down transactions from HPIP, an affiliate of ArcLight Capital Partners, LLC ("ArcLight") who controls our General Partner, and its affiliates, that are complementary to our existing asset base or that provide attractive returns in new operating regions or business lines. We will pursue acquisitions in our areas of operation that we believe will allow us to realize operational efficiencies by capitalizing on our existing infrastructure, personnel and customer relationships. We will also seek acquisitions in new geographic areas or new but related business lines to the extent that we believe we can utilize our operational expertise to enhance our business with these acquisitions, such as the acquisition of the Lavaca System mentioned above.

Develop Strategic and Accretive New Asset Platforms. We plan to selectively pursue the development of new complementary midstream asset platform in our current operating regions and in new midstream asset regions that we believe provide attractive returns. As our customers move to produce in new areas or develop new end-use markets, we seek to provide solutions for their midstream needs. We intend to develop assets in our current lines of business, but may pursue opportunities in new but related business lines as well.

Capitalize on Organic Growth Opportunities Associated with Our Existing Assets. We continually seek to identify and evaluate economically attractive organic expansion and asset enhancement opportunities that leverage our existing asset footprint and strategic relationships with our customers. We expect to have opportunities to expand our systems into new markets and sources of supply, which we believe will make our services more attractive to our customers. We intend to focus on projects that can be completed at a relatively low cost and that have potential for attractive returns.

Attract Additional Volumes to Our Systems. We intend to attract new volumes of natural gas, oil and specialty chemicals to our systems and terminals from existing and new customers by continuing to provide superior customer service and through aggressively marketing our services to additional customers in our areas of operation. We have available capacity on a majority of our systems; as a result, we can accommodate additional volumes at a minimal incremental cost.

Manage Exposure to Commodity Price Risk. We work to manage our commodity price exposure by targeting a contract portfolio that is weighted toward firm transportation, as well as fee-based and fixed-margin contracts, while mitigating direct commodity price exposure by employing a prudent hedging strategy. The GAAP measure most comparable to gross margin is net income. For the years ended December 31, 2014 and 2013, $76.5 million and $48.7 million, or 74.4% and 65.1%, respectively, of our gross margin was generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts, which have little or no direct commodity price exposure. Those contracts, together with our percent-of-proceeds contracts and hedging activities, generated relatively stable cash flows. As of December 31, 2014, we have hedged approximately 4% of our expected exposure to NGL prices through the middle of 2015. With respect to our exposure to natural gas prices, we are long natural gas on certain of our systems and short natural gas on certain of our other systems, which effectively creates a natural hedge against our exposure to fluctuations in the price of natural gas.

Pursue and Maintain Financial Flexibility and Conservative Leverage. We plan to pursue a disciplined financial policy and seek to maintain a conservative capital structure that we believe will allow us to consider attractive growth projects and acquisitions even in challenging commodity price or capital market environments.

Continue Our Commitment to Safe and Environmentally Sound Operations. The safety of our employees and the communities in which we operate is one of our highest priorities. We believe it is critical to safely handle natural gas and NGLs for our customers, while striving to minimize the environmental impact of our operations. We have implemented a safety performance program, including an integrity management program, and planned maintenance programs to increase the safety, reliability and efficiency of our operations.

Competitive Strengths

We believe that we will be able to successfully execute our business strategies because of the following competitive strengths:

Well Positioned to Pursue Opportunities Overlooked by Larger Competitors. Our size and flexibility, in conjunction with our geographically diverse asset base, positions us to pursue economically attractive growth projects and acquisitions that may not be large enough to be attractive to our larger competitors. Given the current size of our business, these opportunities may have a larger positive impact on us than they would have on our competitors and may provide us with material growth opportunities. In addition, as a result of our focus on customer service, we believe that we have unique insights into our customers' needs and are well situated to take advantage of organic growth opportunities that arise from those needs. The benefits of our size and flexibility apply not only to the opportunities around our current assets but to opportunities to develop new asset platforms as well, which allows us to pursue the development of new systems that have the potential to positively impact our company but that would not be meaningful enough to gain the attention of our larger competitors.

Relationship with ArcLight. ArcLight Capital Partners, LLC ("ArcLight") controls the majority owner of our General Partner and has a proven track record of investments across the energy industry value chain. ArcLight bases its investments on fundamental asset values and execution of defined growth strategies with a focus on cash flow generating assets and service companies with conservative capital structures. We believe our growth strategy may benefit from this relationship.

Diversified Asset Base. Our assets are diversified geographically and by business line, which contributes to the stability of our cash flows and creates a number of potential growth avenues for our business. We primarily operate in eight states, have access to multiple sources of natural gas supply, and service various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We believe this diversification provides us with a variety of growth opportunities and mitigates our exposure to reduced activity in any one area.

Strategically Located Assets. Our assets are located in areas where we believe there will be opportunities to access new natural gas, oil and specialty chemical supplies and to capture new customers who are underserved by our competitors. Drilling activity continues on and around the majority of our assets, and we believe that our assets are strategically positioned to capitalize on this drilling activity, increased demand for midstream services and growing commodity consumption in the shale plays of the Bakken, Eagle Ford and Permian as well as East Texas, Gulf Coast and Southeast U.S. regions. This belief is based on:

- the proximity of our gathering and transmission systems to newly producing wells and the relatively lower cost to connect to our systems compared to those farther away;
- the available capacity of our systems, coupled with an ability to economically add capacity to our systems; and
- the availability of multiple downstream interconnects that many of our systems have provides our customers with multiple market delivery options, thereby causing our systems to be more attractive compared to those of our competitors.

Focus on Delivering Excellent Customer Service. We view our strong customer relationships as one of our key assets and believe it is critical to maintain operational excellence and ensure best-in-class customer service and reliability. Furthermore, we believe our entrepreneurial culture and smaller size relative to our peers enables us to offer more customized and creative solutions for our customers and to be more responsive to their needs. We believe our customer focus will enable us to capture new opportunities and expand into new markets.

Experienced Management and Operating Teams. Our executive management team has an average of more than 25 years' experience in the midstream energy industry. The team possesses a comprehensive skill set to support our business and enhance unitholder value through asset optimization, accretive development projects and acquisitions. In addition, our field supervisory team has operated our assets for an average of 20 years. We believe that our field employees' knowledge of the assets will further contribute to our ability to execute our business strategies. Furthermore, the interests of our executive management and operating teams are strongly aligned with those of common unitholders, including through their ownership of common units and participation in our Long-Term Incentive Plan.

Our Assets

We own and operate twelve gathering systems, five processing facilities, three fractionation facilities, three interstate pipelines, five intrastate pipelines and four marine terminal sites. We also own a 66.7% non-operating interest in MPOG, a crude oil gathering and processing system, as well as a 50% undivided, non-operating interest in the Burns Point Plant, a natural gas processing plant. Our primary assets are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, North Dakota, Tennessee and Texas. We organize our operations into three business segments: i) Gathering and Processing; ii) Transmission; and iii) Terminals.

Gathering and Processing Segment

General

Our Gathering and Processing segment consists of midstream natural gas systems that provide the following services to our customers:

- gathering;
- compression;
- treating;
- processing;
- fractionating;
- transportation; and
- sales of natural gas, NGLs and condensate.

Our Gathering and Processing assets are located in Alabama, Louisiana, Mississippi, North Dakota and Texas and in shallow state and federal waters in the Gulf of Mexico off the coast of Louisiana and are positioned in certain areas with active drilling programs and opportunities for organic growth. We continually seek new sources of raw natural gas supply to maintain and increase the throughput volume on our gathering systems and through our processing plants.

We generally derive revenue in our Gathering and Processing segment from fee-based, fixed-margin and POP arrangements, for our producer and supplier customers and our own account. We have no keep-whole arrangements with our customers. For the year ended December 31, 2014, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 48.3% and 51.7%, respectively, of our segment gross margin for the Gathering and Processing segment. For the year ended December 31, 2013, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 29.4% and 70.6%, respectively, of our segment gross margin for the Gathering and Processing segment.

The following table provides information regarding our Gathering and Processing segment assets as of December 31, 2014, and for the years ended December 31, 2014 and 2013.

| | Approximate Gas Gathering System (Miles) | Approximate Design Capacity (MMcf/d) | Compression (Horsepower) | Number of Plants and Fractionators | Approximate Average Throughput (MMcf/d) Year Ended December 31, | |
|---|---|---|---|---|---|---|
| | | | | | 2014 | 2013 |
| Gathering and Processing | | | | | | |
| Lavaca (a) | 203 | 218 | 32,000 | — | 65.0 | — |
| Longview (b) | 620 | 50 | 23,880 | 3 | 4.7 | — |
| Chapel Hill (b) | 90 | 20 | 2,540 | 2 | 4.1 | — |
| Yellow Rose (b) | 47 | 40 | 3,256 | 1 | 1.3 | — |
| Bakken (c) | — | — | — | — | — | — |
| Chatom (d) | 24 | 25 | 3,456 | 2 | 6.4 | 7.6 |
| Bazor Ridge | 169 | 22 | 8,615 | 1 | 9.6 | 10.9 |
| Other (e) | 383 | 711 | 17,290 | 1 | 183.7 | 258.7 |
| Total | 1,536 | 1,086 | 91,037 | 10 | 274.8 | 277.2 |

(a) The Lavaca System was acquired effective January 31, 2014.
(b) The gathering and processing assets of Costar Midstream were acquired effective October 1, 2014.
(c) Crude oil gathering system in the Williston Basin with initial design capacity of 40,000 bbl/d currently under construction.
(d) We have included approximate average throughput at 100% for the Chatom System. As of December 31, 2014, we own a 92.2% undivided interest in the Chatom System. In October 2013, we increased our ownership percentage in the Chatom System from 87.4% to 92.2%.
(e) Other includes our Gloria and Lafitte, Quivira and Burns Point, Magnolia and Offshore Texas systems.

Lavaca System

The Lavaca System consists of 203 miles of high- and low-pressure pipelines ranging from four to eight inches in diameter with 32,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas. The Lavaca System currently has a design capacity of approximately 218 MMcf/d. The system is currently flowing more than 114.7 MMcf/d between sales volumes and gas lift. Natural gas production gathered by the system is compressed and delivered to a third-party for processing or redelivered to producers for gas lift.

Longview System

The Longview gathering and processing system consists of approximately 620 miles of high- and low-pressure gathering lines with diameters ranging from two to twenty inches with a combined compression capacity of 23,880 horsepower. Our Longview System also contains two cryogenic processing plants with a design capacity of approximately 50 MMcf/d, one fractionation unit with 8,500 Bbls/d of capacity, product storage tanks, and truck racks to receive off-spec condensate. The Longview System is located near Longview in Gregg County, Texas. Located adjacent to the Longview System is a rail facility, which is currently under construction, that will transport off-spec condensate. This facility is scheduled to commence operations in the second half of 2015.

Chapel Hill System

The Chapel Hill gathering and processing system consists of approximately 90 miles of gathering lines with a combined compression capacity of 2,540 horsepower. Our Chapel Hill System also contains a cryogenic processing plant with a design capacity of approximately 20 MMcf/d, one fractionation unit with 1,250 Bbls/d of capacity, product storage tanks, and truck racks to deliver propane. The Chapel Hill System is located near Tyler in Smith County, Texas.

Yellow Rose System

The Yellow Rose gathering and processing system consists of approximately 50-miles of low- pressure, rich-gas gathering system and 40 MMcf/d cryogenic processing plant that commenced operations in October, 2014. The Yellow Rose System is located in Martin County, Texas.

Bakken System

The Bakken oil gathering pipeline system, which is currently under construction, will consist of a 39-mile pipeline with capacity to transport up to approximately 40,000 bbls/d crude oil for delivery to the Tesoro Logistics pipeline located Northeast of Watford City, North Dakota. The project is scheduled to commence operations in mid-2015 and will provide producers in the area with access to refinery, rail and pipeline markets.

Chatom System

The Chatom System consists of a 25 MMcf/d cryogenic processing plant, a 1,900 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 24-mile gas gathering system. The system is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi. The Chatom System gathers natural gas from onshore oil and natural gas wells in Alabama and Mississippi.

Bazor Ridge System

The Bazor Ridge gathering and processing system consists of approximately 169 miles of pipeline, with diameters ranging from three to eight inches, and three compressor stations with a combined compression capacity of 1,069 horsepower. Our Bazor Ridge System is located in Jasper, Clarke, Wayne and Greene counties of Mississippi. The Bazor Ridge System also contains a sour natural gas treating and cryogenic processing plant located in Wayne County, Mississippi, with a design capacity of approximately 22 MMcf/d as well as four inlet and one discharge compressor with approximately 5,218 of combined horsepower. The natural gas supply for our Bazor Ridge System is derived primarily from rich associated natural gas produced from oil wells targeting the mature Upper Smackover formation. Production from the wells drilled in this area is generally stable with relatively modest decline rates.

Other Gathering and Processing Systems

Gloria and Lafitte systems. The Gloria gathering system provides gathering and compression services through our assets, as well as processing services through our elective processing arrangements. The Gloria System is located in Lafourche, Jefferson, Plaquemines, St. Charles and St. Bernard parishes of Louisiana and consists of approximately 138 miles of pipeline, with diameters ranging from three to 16 inches, and four compressors with a combined size of 2,962 horsepower. The Gloria System may experience excess volumes from our Lafitte system. The Lafitte gathering system consists of approximately 40 miles of gathering pipeline, with diameters ranging from four to 12 inches and a design capacity of approximately 71 MMcf/d. The Lafitte System originates onshore in southern Louisiana and terminates in Plaquemines Parish, Louisiana, at the Alliance Refinery owned by Phillips 66. We are the sole supplier of natural gas to the Alliance Refinery through our Lafitte and Gloria systems. We supply natural gas to the Alliance Refinery pursuant to a long-term contract that expires in 2023. Any natural gas not used by Phillips 66 at the Alliance Refinery is delivered to our Gloria System.

Quivira and Burns Point Systems. The Quivira gathering system consists of approximately 34 miles of pipeline, with a 12-inch diameter mainline and several laterals ranging in diameter from six to eight inches. The system originates offshore of Iberia and St. Mary parishes of Louisiana in Eugene Island Block 24 and terminates onshore in St. Mary Parish, Louisiana, at a connection with the Burns Point Plant, a cryogenic processing plant with a design capacity of 165 MMcf/d that is jointly owned by us and the plant operator, Enterprise Gas Processing, LLC ("Enterprise"). We hold a 50% undivided, non-operating interest in the Burns Point Plant. We acquired an interest in the asset group and do not hold an interest in a legal entity. We and Enterprise are proportionately liable for the liabilities. Outside of the rights and responsibilities of the operator, we and Enterprise have equal rights and obligations to the assets. Significant non-capital and maintenance capital expenditures, plant expansions and significant plant dispositions require the approval of both owners.

Magnolia System. The Magnolia gathering system is a Section 311 intrastate pipeline that gathers coal-bed methane in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transcontinental Gas Pipe Line Co. ("Transco") pipeline system, an interstate pipeline owned by The Williams Companies, Inc. The Magnolia System consists of approximately 116 miles of pipeline with small-diameter gathering lines and trunk lines ranging from six to 24 inches in diameter and one compressor station with 3,328 horsepower.

Offshore Texas System. The Offshore Texas System consists of the GIGS and Brazos systems, two parallel gathering systems that share common geography and operating characteristics and have approximately 56 miles of pipeline with diameters ranging from six to 16 inches and a design capacity of approximately 100 MMcf/d. The Offshore Texas System provides gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico offshore Texas.

Customers and Contracts

With respect to our Gathering and Processing segment, substantially all of the natural gas produced on our Lavaca System is delivered to Penn Virginia Corporation for processing. On our Gloria and Lafitte systems, we have a buy/sell agreement whereby most of the natural gas is sold to ConocoPhillips for use at the Alliance Refinery in Plaquemines Parish, Louisiana, under a contract that expires in 2023. On our Chatom System, we have a POP arrangement with Mississippi Resources, LLC. that contains an acreage dedication under a contract that expires in 2021. On our Chatom System, we have a sales arrangement with Shell. On our Bazor Ridge System, we have a POP arrangement with Venture Oil & Gas Co. that contains an acreage dedication under a contract that expires in 2015 and is currently in negotiations. We have a weighted-average remaining life of approximately 15 years on our fee-based contracts in this segment. The weighted-average remaining life on our POP contracts in this segment is less than two years. For the year ended December 31, 2014, our Gathering and Processing segment derived 33% and 12% of its revenue from ConocoPhillips and Shell, respectively. For the year ended December 31, 2013, our Gathering and Processing segment derived 43% and 19% of its revenue from ConocoPhillips and Shell, respectively.

Transmission Segment

General

Our Transmission segment is comprised of interstate and intrastate pipelines that transport natural gas from interconnection points on other large pipelines or production points to customers, such as local distribution companies ("LDCs"), electric utilities, direct-served industrial complexes, or to interconnects on other pipelines. Certain of our pipelines are subject to regulation by FERC and by state regulators. In this segment, we often enter into firm transportation contracts with our shipper customers to transport natural gas sourced from large interstate or intrastate pipelines. Our Transmission segment assets are located in multiple parishes in Louisiana, including onshore and offshore producing regions around southeast Louisiana, and multiple counties in Mississippi, Alabama and Tennessee.

The following table provides information regarding our Transmission segment assets as of December 31, 2014, and for the years ended December 31, 2014 and 2013.

| | Approximate Transmission System (Miles) | Jurisdiction | Compression (Horsepower) | Approximate Design Capacity (MMcf/d) | Approximate Average Throughput (MMcf/d) Year Ended December 31, | |
|---|---|---|---|---|---|---|
| | | | | | 2014 | 2013 |
| Transmission | | | | | | |
| High Point | 651 | Intrastate | — | 1,120 | 427.3 | 279.4 |
| Midla/MLGT | 427 | Interstate/Intrastate | 3,600 | 368 | 183.8 | 193.0 |
| Other (a) | 427 | Interstate/Intrastate | 3,665 | 985 | 167.8 | 178.1 |
| Total | 1,505 | | 7,265 | 2,473 | 778.9 | 650.5 |

(a) Includes the AlaTenn, Bamagas, Chalmette and TriGas systems.

High Point System

The High Point System consists of approximately 651 miles of natural gas and liquids pipeline assets located in southeast Louisiana and the shallow water and deep shelf Gulf of Mexico. The High Point System gathers natural gas from both onshore and offshore producing regions around southeast Louisiana. The onshore footprint is Plaquemines and St. Bernard Parish, Louisiana. The offshore footprint consists of the following federal Gulf of Mexico zones: Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound. Natural gas is collected at more than 75 receipt points that connect to hundreds of wells targeting various geological zones in water depths up to 1,000 feet, with an emphasis on oil and liquids-rich reservoirs. The High Point System is comprised of FERC-regulated transmission assets and non-jurisdictional gathering assets, both of which accept natural gas from well production and interconnected pipeline systems. The High Point System delivers the natural gas to the Toca Gas Processing Plant, operated by Enterprise, where the products are processed and the residue gas is sent to an unaffiliated interstate system owned by Kinder Morgan.

Midla and MLGT Systems

Our Midla System is an interstate natural gas pipeline with approximately 370 miles of pipeline linking the Monroe Natural Gas Field in northern Louisiana and interconnections with the Transco Pipeline System and Gulf South Pipeline System to customers near Baton Rouge, Louisiana.

The northern portion of the system, including the T-32 lateral, consists of approximately four miles of high-pressure, 12-inch-diameter pipeline. Natural gas on the northern end of the Midla System is delivered to two power plants operated by Entergy by way of the T-32 lateral and the CLECO Sterlington plant by way of the Sterlington lateral.

The mainline has a design capacity of approximately 198 MMcf/d and consists of approximately 170 miles of low-pressure, 22-inch-diameter pipeline with laterals ranging in diameter from two to 16 inches. This section of the Midla System primarily serves small LDCs under firm transportation contracts that automatically renew on a year-to-year basis. Substantially all of these contracts are at the maximum rates allowed under Midla's FERC tariff.

The southern portion of the system, including interconnections with the MLGT System and other associated laterals, consists of approximately two miles of high- and low-pressure, 12-inch-diameter pipeline. This section of the system primarily serves industrial and LDC customers in the Baton Rouge market through contracts with several large marketing companies. In addition, this section includes two small offshore gathering lines, the T-33 lateral in Grand Bay and the T-51 lateral in Eugene Island 28, each of which are approximately five miles in length.

The MLGT System is an intrastate transmission system that sources natural gas from interconnects with the FGT Pipeline system, the Tetco Pipeline system, the Transco Pipeline system and our Midla System to a Baton Rouge, Louisiana refinery owned and operated by ExxonMobil and several other industrial customers. Our MLGT System has a design capacity of approximately 170 MMcf/d and is comprised of approximately 54 miles of pipeline with diameters ranging from three to 14 inches. The MLGT System is connected to seven receipt and 17 delivery points.

On October 8, 2014, the Partnership reached an agreement in principle regarding its Midla interstate pipeline. The parties involved reached the agreement in principle in order to provide continued service to Midla's customers while addressing safety concerns with the existing pipeline.

Midla and the parties agreed that Midla may retire the existing mainline and replace the existing natural gas service with a new pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the "Natchez Line") to serve existing residential, commercial, and industrial customers. Customers not served by the new Natchez Line would be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service. Further, the northern and southern portions of the system will be transferred to MLGT, which will continue to operate. The agreement is subject to final agreement by the parties and ongoing proceedings by the FERC. Under the agreement in principle and subject to FERC approval, Midla will execute long-term agreements to recover its investment in the Natchez Line.

Other Systems

AlaTenn System. The AlaTenn System is an interstate natural gas pipeline that interconnects with TGP and travels west to east delivering natural gas to industrial customers in northwestern Alabama, as well as the city gates of Decatur and Huntsville, Alabama. Our AlaTenn System has a design capacity of approximately 200 MMcf/d and is comprised of approximately 294 miles of pipeline with diameters ranging from three to 16 inches and includes two compressor stations with combined capacity of 3,665 horsepower. The AlaTenn System is connected to over 25 active delivery and four receipt points, including the Tetco Pipeline system, an interstate pipeline owned by Spectra Energy Transmission, LLC, and the Columbia Gulf Pipeline system, an interstate pipeline owned by NiSource Gas Transmission and Storage.

Bamagas System. Our Bamagas System is a Hinshaw intrastate natural gas pipeline that travels west to east from an interconnection point with TGP in Colbert County, Alabama, to two power plants in Morgan County, Alabama. The Bamagas System consists of 52 miles of high-pressure, 30-inch pipeline with a design capacity of approximately 450 MMcf/d. Currently, 100% of the throughput on this system is contracted under long-term firm transportation agreements.

Our other transmission systems include the Chalmette System, located in St. Bernard Parish, Louisiana, and the Trigas System, located in three counties in northwestern Alabama. The approximate design capacities for the Chalmette and Trigas systems are 125 MMcf/d and 60 MMcf/d, respectively. Finally, we also own a number of miscellaneous interconnects and small laterals that are collectively referred to as the SIGCO assets.

Customers

In our Transmission segment, we contract with LDCs, electric utilities, or direct-served industrial complexes, or to interconnections on other large pipelines, to provide firm and interruptible transportation services.

For our High Point systems, we have interruptible transportation contracts in place with various customers operating in both onshore and offshore producing regions around southeast Louisiana. In addition, we have a fixed-margin arrangement on our MLGT System whereby we purchase and sell the natural gas that we transport.

On the Bamagas System, there are two firm transportation contracts providing for a total of 200 MMcf/d of firm transportation capacity. These contracts, which expire in 2020, ensure steady natural gas supply for the Morgan and Decatur Energy Centers in Morgan County, Alabama. These two natural gas fired power plants were built in 2002 and 2003 and have a combined capacity of 1,502 megawatts. These generating facilities supply the Tennessee Valley Authority ("TVA") with electricity under long-term contractual arrangements between Calpine Corporation and the TVA.

For our Midla and AlaTenn systems, and a portion of our High Point systems, which are interstate natural gas pipelines, the maximum and minimum rates for services are governed by each individual system's FERC-approved tariff. In some cases, with FERC approval, we can have rates or certain other terms that are different from those generally provided for in the FERC tariff. For our Bamagas and MLGT systems, which are intrastate pipelines providing interstate services under the Hinshaw exemption of the Natural Gas Act ("NGA"), we negotiate service rates with each of our shipper customers.

Within the Transmission segment, the weighted-average remaining life of our firm and interruptible transportation contracts are approximately five years and less than one year, respectively. ExxonMobil and Enbridge Marketing (US) L.P. are the two largest purchasers of natural gas and transmission capacity in our Transmission segment and accounted for approximately 43% and 16%, respectively, of our segment revenue for the year ended December 31, 2014. For the year ended December 31, 2013, ExxonMobil and Enbridge Marketing (US) L.P. accounted for approximately 39% and 16%, respectively, of our segment revenue.

Terminals Segment

General

Our Terminals segment consists of 1.7 million barrels of storage capacity across four marine terminal sites located in Westwego, Louisiana; Brunswick, Georgia; Harvey, Louisiana; and Salisbury, Maryland. Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners, and chemical manufacturers, to store a range of products, including petroluem products, distillates, chemicals and agricultural products.

The following table provides information regarding our Terminals segment assets as of December 31, 2014, and for the years ended December 31, 2014 and 2013.

| | | | | Storage Utilization (%) Year Ended December 31, | |
|---|---|---|---|---|---|
| Terminals | Number of Tanks | Approximate Contracted Capacity (Bbls) | Approximate Design Capacity (Bbls) | 2014 | 2013 (b) |
| Westwego | 48 | 1,044,600 | 1,044,600 | 100.0% | 100.0% |
| Brunswick | 5 | 221,000 | 221,000 | 100.0 | 100.0 |
| Harvey (a) | 16 | 39,000 | 237,800 | 16.4 | — |
| Salisbury | 16 | 83,470 | 171,620 | 48.6 | 74.0 |
| Total | 85 | 1,388,070 | 1,675,020 | 82.9% | 96.2% |

(a) Harvey terminal commenced operations in July of 2014.
(b) Terminals amounts are for the period from April 15, 2013 to December 31, 2013 for the year ended December 31, 2013.

Westwego Terminal Operations

The Westwego Terminal site consists of 48 above-ground storage tanks with a combined capacity of 1,044,600 barrels. Our operations support many different commercial customers, including commodity brokers, refiners and chemical manufacturers. Our location within the Port of New Orleans, the warehousing and international distribution attributes this location provides, along with our broad customer base, contributes to the potential diversity of the products customers may want stored in our terminal. The products will generally fall into two broad categories: chemical and agricultural.

Our income from the Westwego Terminal is derived from storage capacity contracts, throughput charges for receipt and delivery of our customers' products; and other services requested by our customers, such as blending services. The terms of our storage capacity contracts range from month-to-month to multiple years, with renewal options.

At the Westwego Terminal, we generally receive our customers' liquid product by river vessel at our Mississippi River dock and by railcar. The product is transferred from the river vessels and railcars to the specified storage tank via the terminal's internal pipeline system. The customer's product is removed from storage at our terminal by truck, railcar and/or water vessel. The length of time that the customer's product is held in storage without transfer varies depending upon the customer's needs.

Brunswick Terminal Operations

The Brunswick Terminal site consists of one 60,000-barrel above-ground storage tank, two 80,000-barrel above-ground storage tanks and two 500-barrel above-ground storage tanks with a combined capacity of 221,000 barrels. The Brunswick Terminal is currently leasing land from the Georgia Ports Authority pursuant to a lease that is scheduled to terminate on September 4, 2016, which we plan to renew.

This terminal is ideally suited to serve petroleum, chemical and agricultural customers who need deep-water access and distribution in the southeastern sector of the United States. Income from the Brunswick Terminal is derived from storage capacity contracts, throughput charges for receipt and delivery of our customers' products and other services requested by our customers, such as blending services. The terms of our storage capacity contracts will range from month-to-month to multiple years, with renewal options.

At the Brunswick Terminal we offer product transfer via river vessel, railcar and bulk-liquid carrying truck. At the Brunswick Terminal, the customer's liquid product is received by barge or ship at the dock. The product is transferred from barges or ships to the storage tank via the terminal's internal pipeline system. The customer's product is removed from storage at our terminal by truck, railcar and/or barge or ship. The length of time that the customer's product is to be held in storage without transfer will vary depending on the customer's needs.

Harvey Terminal Operations

The Harvey Terminal consists of approximately 56 acres of property and facilities located in Harvey, Louisiana adjacent to the Mississippi River. Terminal storage operations at Harvey commenced in July of 2014 and currently consists of sixteen above-ground storage tanks with a combined capacity of approximately 240,000 barrels. Construction of a deep-water ship dock is currently underway with completion expected in the second quarter of 2015. Upon completion, Harvey is expected to be a full-service storage site, providing rail, truck, barge, and deep-water service. The Harvey terminal has the potential for more than two million barrels of capacity when fully developed.

Salisbury Terminal Operations

The Salisbury Terminal site, which is currently presented as held-for-sale, consists of 16 above-ground storage tanks with a combined capacity of approximately 172,000 barrels. This terminal is ideally suited to serve petroleum distributors and agricultural customers who need distribution in the Delmarva Peninsula area of Maryland. Income from the Salisbury Terminal is derived from throughput charges for receipt and delivery of our customers' products, as well as other services. The terms of our storage capacity contracts will range from month-to-month, to multiple years, with renewal options.

At the Salisbury Terminal, we offer product transfer via river barges and by bulk-liquid carrying truck. The customer's liquid product is primarily received by barge at the dock. The product is transferred from barges to the storage tank via the terminal's internal pipeline system. The customer's product is removed from storage at our terminal by truck. The length of time that the customer's product is to be held in storage without transfer will vary depending on the customer's needs.

The Salisbury Terminal is currently under contract to be sold with an expected close date within the first quarter of 2015.

Customers

In our Terminals segment, we generally receive fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services provided to our customers, such as excess throughput, truck weighing, etc. The terms of our firm storage contracts are multiple years, with renewal options.

Among all of our customers in this segment, the weighted-average remaining life of our guaranteed firm storage contracts are approximately three years. Shrieve Oilfield Products Group and Shell are the two largest customers in our Terminals segment and accounted for approximately 19% and 20%, respectively, of our segment revenue for the year ended December 31, 2014. Shrieve Oilfield Products Group and Shell accounted for approximately 20% and 17%, respectively, of our segment revenue for the year ended December 31, 2013.

Competition

The natural gas gathering, compression, treating and transportation business is very competitive. Our competitors in our Gathering and Processing segment include other midstream companies, producers, intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. Our major competitors in this segment include TGP, Gulf South, ANR Pipeline, Columbia Gulf, DCP Midstream, and Enbridge.

Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

In our Transmission segment, we compete with other pipelines that serve regional markets, specifically in our Baton Rouge market. An increase in competition could result from new pipeline installations or expansions of existing pipelines. Competitive factors include the commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and gas quality issues. Our major competitors for this segment are Southern Natural Gas Company, Louisiana Intrastate Gas, and EnLink.

In our Terminals segment, we compete with a number of existing storage facilities within the New Orleans to Baton Rouge, Louisiana refining and manufacturing corridor, the southeast USA, Florida and Georgia area and the Delmarva, Maryland Peninsula area. Our major competitors for this segment are Kinder Morgan, International Matex Tank Terminals, Westway Group, Stolt Terminals, Vopak, and LBC Tank Terminals.

Other Segment Information

For additional information on our segments, including revenues from customers, profit or loss and total assets, please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 15. "Exhibits and Financial Statement Schedules."

Safety and Maintenance

We are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA"), and by the Pipeline Safety Improvement Act of 2002 ("PSIA"), which was recently reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas. The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in "high-consequence areas," such as high population areas. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The PHMSA issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. We believe that this rule does not apply to any of our pipelines. While we cannot predict the outcome of these legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines not previously subject to such requirements. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the costs of compliance associated with such requirements.

We regularly inspect our pipelines, and third parties assist us in interpreting the results of the inspections.

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

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency ("EPA"), community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act (Superfund") and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities, and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management ("PSM") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety, Superfund and PSM.

We and the entities in which we own an interest are subject to:

- EPA Chemical Accident Prevention Provisions, also known as the Risk Management Plan requirements, which are designed to prevent the accidental release of toxic, reactive, flammable or explosive materials; and
- Department of Homeland Security Chemical Facility Anti-Terrorism Standards, which are designed to regulate the security of high-risk chemical facilities.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Regulation of our terminals require us to maintain and currently hold approvals and permits from federal, state and local regulatory agencies for air quality and water discharge, as well as standard local occupational licenses.

Interstate Natural Gas Pipeline Regulation

Our interstate natural gas transportation systems are subject to the jurisdiction of FERC pursuant to the NGA. Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation of our interstate pipelines extends to such matters as:

- rates, services, and terms and conditions of service;
- the types of services offered to customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory.

The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenue associated with providing transportation service.

In 2008, FERC issued Order No. 717, a final rule that implements standards of conduct that include three primary rules: (1) the "independent functioning rule," which requires transmission function and marketing function employees to operate independently of each other; (2) the "no-conduit rule," which prohibits passing transmission function information to marketing function employees; and (3) the "transparency rule," which imposes posting requirements to help detect any instances of undue preference. The FERC has since issued four rehearing orders that generally reaffirmed the determinations in Order No. 717 and also clarified certain provisions of the Standards of Conduct.

In 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass through partnership entity to reflect actual or potential income tax liability on public utility income, if the pipeline proves that the ultimate owner of its interests has an actual or potential income tax liability on such income. The policy statement provided that whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In August 2005, FERC dismissed requests for rehearing of its new policy statement. In December 2005, the FERC issued its first significant case-specific review of the income tax allowance issue in another pipeline partnership's rate case. The FERC reaffirmed its income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The tax allowance policy and the December 2005 order were appealed to the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. The D.C. Circuit denied these appeals in May 2007 in ExxonMobil Oil Corporation v. FERC and fully upheld the FERC's tax allowance policy and the application of that policy in the December 2005 order. In 2007, the D.C. Circuit denied rehearing of its ExxonMobil decision. The ExxonMobil decision, its applicability, other orders issued by the FERC upholding the FERC's income tax allowance policy and the issue of the inclusion of an income tax allowance have been the subject of extensive litigation before the FERC. The FERC's most recent order upholding the policy was issued in September 2012. Several parties have appealed this FERC order. Whether a pipeline's owners have actual or potential income tax liability continues to be reviewed by FERC on a case-by-case basis. How the FERC applies the income tax allowance policy to pipelines owned by publicly traded partnerships could impose limits on a pipeline's ability to include a full income tax allowance in its cost of service.

In April 2008, the FERC issued a Policy Statement regarding the composition of proxy groups for determining the appropriate return on equity for natural gas and oil pipelines using FERC's Discounted Cash Flow ("DCF") model for setting cost-of-service or recourse rates. The FERC denied rehearing and no petitions for review of the Policy Statement were filed. In the policy statement, FERC concluded, among other matters that MLPs should be included in the proxy group used to determine return on equity for both oil and natural gas pipelines, but the long-term growth component of the DCF model should be limited to fifty percent of long-term gross domestic product. The adjustment to the long-term growth component, and all other things being equal, results in lower returns on equity than would be calculated without the adjustment. However, the actual return on equity for our interstate pipelines will depend on the specific companies included in the proxy group and the specific conditions at the time of the future rate case proceeding. FERC's policy determinations applicable to MLPs are subject to further modification.

Section 311 Pipelines

Intrastate transportation of natural gas is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce without an exemption under the NGA, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA, and Part 284 of the FERC's regulations. Pipelines providing transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis. The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates, terms and conditions of some transportation services provided on our Section 311 pipeline systems are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to FERC's review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved statement of operating conditions could result in alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

Hinshaw Pipelines

Intrastate natural gas pipelines are defined as pipelines that operate entirely within a single state, and generally are not subject to FERC's jurisdiction under the NGA. Hinshaw pipelines, by definition, also operate within a single state, but can receive gas from outside their state without becoming subject to FERC's NGA jurisdiction. Specifically, Section 1(c) of the NGA exempts from the FERC's NGA jurisdiction those pipelines that transport gas in interstate commerce if (1) they receive natural gas at or within the boundary of a state, (2) all the gas is consumed within that state and (3) the pipeline is regulated by a state commission. Following the enactment of the NGPA, the FERC issued Order No. 63 authorizing Hinshaw pipelines to apply for authorization to transport natural gas in interstate commerce in the same manner as intrastate pipelines operating pursuant to Section 311 of the NGPA. Hinshaw pipelines frequently operate pursuant to blanket certificates to provide transportation and sales service under the FERC's regulations.

Historically, FERC did not require intrastate and Hinshaw pipelines to meet the same rigorous transactional reporting guidelines as interstate pipelines. However, as discussed below, in 2010 the FERC issued a new rule, Order No. 735, which increases FERC regulation of certain intrastate and Hinshaw pipelines. See "Market Behavior Rules; Posting and Reporting Requirements."

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. However, some of our natural gas gathering activity is subject to Internet posting requirements imposed by FERC as a result of FERC's market transparency initiatives. We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC's efforts to promote open access, transparency, and the unbundling of interstate pipeline services has prompted a number of interstate pipelines to transfer their non-jurisdictional gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional 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 our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas 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 regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no adverse effect to our system due to these regulations.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, ("EP Act 2005"). Among other matters, the EP Act 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of the EP Act 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise 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. The EP Act 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes, up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines.

The EP Act of 2005 also added a section 23 to the NGA authorizing the FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of annual quantities of natural gas of 2,200,000 MMBtu or more, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. In June 2010, the FERC issued the last of its three orders on rehearing further clarifying its requirements.

In May 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission's periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 became effective on April 1, 2011. In December 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and "Hinshaw" pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract.

In July 2010, for the first time the FERC issued an order finding that the prohibition against buy/sell arrangements applies to interstate open access services provided by Section 311 and Hinshaw pipelines. The FERC denied the numerous requests for rehearing of the July order. However, in October 2010, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether and how parties that hold firm capacity on some intrastate pipelines can allow others to use their capacity, including to what extent buy/sell transactions should permitted and whether the FERC should consider requiring such pipelines to offer capacity release programs. In the Notice of Inquiry, the FERC granted a blanket waiver regarding such transactions while the FERC is considering these policy issues. The comment period has ended but the FERC has not issued an order.

Offshore Natural Gas Pipelines

Our offshore natural gas gathering pipelines are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires that all pipelines operating on or across the outer continental shelf provide open and nondiscriminatory access to shippers. From 1982 until 2012, the Minerals Management Service ("MMS"), of the U.S. Department of the Interior ("DOI"), was the federal agency that managed the nation's oil, natural gas, and other mineral resources on the outer continental shelf, which is all submerged lands lying seaward of state coastal waters which are under U.S. jurisdiction, and collected, accounted for, and disbursed revenues from federal offshore mineral leases. On June 18, 2010, the Minerals Management Service was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"). In October 2011, the BOEMRE was reorganized into and replaced by two separate agencies, the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE"). The BOEM manages the exploration and development of the nation's offshore resources. BOEM seeks to appropriately balance economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development and environmental reviews and studies.

BSEE works to promote safety, protect the environment, and conserve resources offshore through vigorous regulatory oversight and enforcement.

Sales of Natural Gas and NGLs

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC"), and the Federal Trade Commission ("FTC"). Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Sales of NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

As discussed 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 interstate natural gas pipelines and those initiatives may also affect the intrastate transportation of natural gas both directly and indirectly.

Environmental Matters

General

Our operation of pipelines, plants, terminals and other facilities for the gathering, compressing, treating and transporting of natural gas and other products is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- delaying system modification or upgrades during permit reviews;
- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and

- enjoining the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

The 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 we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat and transport natural gas. We cannot assure, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), 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 the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate little hazardous waste; however, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and, therefore, be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated soil and groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Oil Pollution Act

In January of 1974, the EPA adopted regulations under the Oil Pollution Act ("OPA"). These oil pollution prevention regulations require the preparation of a Spill Prevention Control and Countermeasure Plan ("SPCC") for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the

United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility's operations comply with the requirements. To be in compliance, the facility's SPCC Plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intra-facility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC Plan and train personnel in its execution. We believe that our facilities will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations and processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we are in substantial compliance with these requirements. As EPA issues new, lower National Ambient Air Quality standards ("NAQQS"), we may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For example, in June 2010, EPA issued a new NAAQS for sulfur dioxide, or SO2, and replaced the 24-hour and annual standards with a more stringent hourly standard. In May 2014, EPA proposed to allow states to use modeling, as well as monitoring, to assess what areas meet the standard. States and EPA have not yet completed the designation process. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Our Bazor Ridge processing plant processes natural gas that is high in hydrogen sulfide, or H2S. This plant has a Title V Air Permit, which is a permit issued pursuant to Title V of the federal Clean Air Act for larger sources of air emissions. In Mississippi, where the Bazor Ridge plant is located, the Title V program is administered by the Mississippi Department of Environmental Quality. Under this permit, we are allowed to emit up to a specified level of sulfur dioxide, or SO2, per year.

Water Discharges

The Federal Water Pollution Control Act ("Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. SPCC requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flow.

Safe Drinking Water Act

The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. We own and operate an acid gas disposal well in Wayne County, Mississippi, as part of our Bazor Ridge gas treating facilities. This well takes a combination of hydrogen sulfide and carbon dioxide recovered from the raw field natural gas feeding the Bazor Ridge Gas plant and injects it into an underground formation permitted for this purpose. The well received an Underground Injection Control ("UIC") Class 2 permit through the Mississippi state oil and gas board in 1999. As part of our permit requirements, we perform regular inspection, maintenance and reporting to the state on the condition and operations of this well which is adjacent to our processing plant. We believe that our facilities will not be materially adversely affected by such requirements.

Endangered Species

The Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

National Environmental Policy Act

The National Environmental Policy Act ("NEPA") establishes a national environmental policy and goals for the protection, maintenance, and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC approval must undergo NEPA review. Many of our activities are covered under categorical exclusions that result in a shorter NEPA review process. The Council on Environmental Quality has issued final guidance to reinvigorate NEPA reviews that, while intended to streamline the process, may result in longer review processes that could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Climate Change

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHG") which include carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to the scientific studies, international negotiations to address climate change have occurred. The United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," became effective on February 16, 2005 as a result of these negotiations, but the United States did not ratify the Kyoto Protocol. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17 percent compared to 2005 levels. We continue to monitor the international efforts to address climate change. Their effect on our operations cannot be determined with any certainty at this time.

In the U.S., legislative and regulatory initiatives are underway to limit GHG emissions. The U.S. Congress has considered legislation that would control GHG emissions through a “cap and trade” program and several states have already implemented programs to reduce GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act (“CAA”) definition of an “air pollutant,” and in response the EPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. In 2010, the EPA issued a final rule, known as the “Tailoring Rule,” that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act. The D. C. Circuit upheld the Tailoring Rule, but in June 2014 Supreme Court overturned the D.C. Circuit and invalidated portions of the Tailoring Rule to the extent the rules impose a requirement to obtain a permit based solely on emissions of GHG. Large sources of other air pollutants such as Volatile Organic Compounds, however, could still be required to install technologies to reduce GHG emissions. In June 2013, President Obama also issued a Climate Action Plan to address climate change through a variety of executive actions, including reduction of methane emissions from oil and gas production and processing operations. On January 14, 2015, the Obama Administration announced additional steps to reduce methane from the oil and gas sector by 40-45% by 2025. These actions include a commitment from EPA to issue standards for methane and volatile organic compounds for new and modified natural gas processing and transmission sources. EPA plans to propose the rule in 2015 and finalize the standards in 2016. EPA has not yet committed to develop existing source standards for methane. These actions signal a new focus on methane emissions that have the potential to pose substantial regulatory risks to our operations.

In addition, on September 2009, the EPA issued a final rule requiring the reporting of GHGs from specified large GHG emission sources in the U.S. beginning in 2011 for emissions in 2010. Our Bazor Ridge and Chatom systems are currently required to and have reported under this rule in 2012 and 2011. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting to include onshore and offshore oil and natural gas systems beginning in 2012. We timely filed emissions reports for our Bazor Ridge and Chatom systems. In December 2014, EPA proposed revisions to the GHG Reporting Rules that would add gathering and boosting facilities and blowdowns of natural gas transmission pipelines to the list of covered facilities. A final rule is expected in 2015.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The majority of scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous. Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems and our insurance may not cover all associated losses. We 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 our business.

Anti-terrorism Measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. Three of our facilities have more than the threshold quantity of listed chemicals; therefore, a "Top Screen" evaluation was submitted to the DHS. The DHS reviewed this information and made the determination that none of the facilities are considered high-risk chemical facilities.

Title to Properties and Rights-of-Way

Our real property falls into two categories: i) parcels that we own in fee and ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remaining land on which our plant sites and major facilities are located, are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. Our predecessors leased or owned these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership in such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Employees

We do not have any employees. The officers of our General Partner manage our operations and activities. As of December 31, 2014, our General Partner employed approximately 287 people who provide direct, full-time support to our operations. All of the employees required to conduct and support our operations are employed by our General Partner. None of these employees are covered by collective bargaining agreements, and our General Partner considers its employee relations to be positive.

General

We make certain filings, and amendments thereto, with the Securities and Exchange Commission (the "SEC"), including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports. All of these filings are available as soon as reasonably practicable after the electronic filing with the SEC free of charge on our website, www.americanmidstream.com. The filings are also available at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549 or by calling the SEC at 1-800-SEC-0330. Additionally, the filings are available on the internet at www.sec.gov. The information contained on our website is not part of, nor is it incorporated by reference into, this Annual Report on Form 10-K.

Item 1A. Risk Factors

Limited partner units are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in this Annual Report in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment in us.

Risks Related to our Business

Our credit facility includes financial covenants and ratios. We may have difficulty maintaining compliance with such financial covenants and ratios, which include a maximum leverage ratio on a quarterly basis, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We depend on our credit facility for future capital needs and to fund a portion of cash distributions to unitholders, as necessary. We are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of financial markets and commodity price levels. Our failure to comply with any of the covenants under our credit facility could result in a default, which could cause all of our existing indebtedness to become immediately due and payable.

We may not have sufficient cash from operations following the preferred distribution on our Series A convertible preferred units, the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our General Partner, to enable us to pay the minimum quarterly distribution to holders of our common and Series B Units.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution of $0.4125 per common unit or distributions associated with Series B Units. These distributions may only be made from cash available for distribution after the preferred quarterly distribution to which our Series A convertible preferred units ("Series A Units") are entitled, the establishment of cash reserves, and payment of our fees and expenses. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volume of natural gas we gather, process and transport;
- the level of production of oil and natural gas and the resultant market prices of oil and natural gas and NGLs;
- realized pricing impacts on our revenue and expenses that are directly subject to commodity price exposure;
- the market prices of natural gas and NGLs relative to one another, which affects our processing margins;
- capacity charges and volumetric fees associated with our transportation services;
- storage capacity utilization associated with our terminals segment;
- the level of competition from other midstream energy companies in our geographic markets;
- the level of our operating, maintenance and general and administrative costs;
- regulatory action affecting the supply of, or demand for, natural gas, the transportation rates we can charge on our regulated pipelines, how we contract for services, our existing contracts, our operating costs and our operating

flexibility; and
- acts of God.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

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

Because of the natural decline in production from existing wells in our areas of operation, our success depends on our ability to obtain new sources of natural gas, which is dependent on factors beyond our control. Any decrease in the volumes of natural gas that we gather, process or transport could adversely affect our business and operating results.

The natural gas volumes that support our business are dependent on the level of production from natural gas and oil wells connected to our systems, including volumes from significant customers, the production of which will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas. The primary factors affecting our ability to obtain non-dedicated sources of natural gas include i) the level of successful drilling activity in our areas of operation and ii) our ability to compete for volumes from successful new wells.

We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things:

- prevailing and projected oil and natural gas and NGL prices;
- the availability and cost of capital;
- prevailing and projected oil and natural gas and NGL prices;
- demand for oil, natural gas and NGLs;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits; and
- the availability of drilling rigs and other production and development costs.

Fluctuations in energy prices, like the recent declines in commodity prices of oil and natural gas, can also greatly affect the development of new oil and natural gas reserves. Further declines in natural gas prices could have a negative impact on exploration, development and production activity, and, if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our assets. We are unable to predict future potential movements in the market price for natural gas, oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices continue to trend lower as they did in the latter part of 2014 and early 2015, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants in our revolving credit facility. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

Because of these and other factors, even if new natural gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, it could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

Natural gas, NGL and other commodity prices are volatile, and a reduction in these prices in absolute terms, or an adverse change in the prices of natural gas and NGLs relative to one another, could adversely affect our gross margin and cash flow and our ability to make distributions to our unitholders.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. Natural gas prices have been under downward pressure in recent years and were highly volatile in 2014. The NYMEX daily settlement price for natural gas for the forward month contract in 2014 ranged from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu. NGL prices are generally positively correlated to the price of WTI crude oil, which has also exhibited frequent and substantial fluctuations. Oil prices declined dramatically in late 2014. The NYMEX daily settlement price for WTI crude oil for the forward month contract in 2014 ranged from a high of $107.26 per Bbl to a low of $53.27 per Bbl.

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

- worldwide economic conditions;
- worldwide political events, including actions taken by foreign oil and gas producing nations;
- worldwide weather events and conditions, including natural disasters and seasonal changes;
- the levels of world-wide and domestic production and consumer demand;
- the availability of imported liquefied natural gas, or LNG;

- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of oil, natural gas, NGLs and other commodities.

In our Gathering and Processing segment, we have exposure to direct commodity price risk under percent-of-proceeds processing contracts as well as under our elective processing arrangements. Under percent-of-proceeds arrangements, we generally purchase natural gas from producers and retain an agreed percentage of the proceeds (in cash or in-kind) from the sale at market prices of pipeline-quality natural gas and NGLs resulting from our processing activities. We also purchase natural gas at various receipt points, process the gas at a third-party owned natural gas processing facility and sell our portion of the residue gas and NGLs. Under percent-of-proceeds arrangements, our revenue and our cash flows increase or decrease as the prices of natural gas, NGLs and oil fluctuate. When we process natural gas that we purchase for our own account, the relationship between natural gas prices and NGL prices also affects our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for us to process the natural gas that we purchase and process for our own account. When natural gas prices are high relative to NGL prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and because of the increased cost (principally that of natural gas shrink that occurs during processing and use of natural gas as a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed pursuant to our elective processing arrangements. For the years ended December 31, 2014 and 2013, percent-of-proceeds arrangements accounted for approximately 25.6% and 34.9%, respectively, of our gross margin, or 51.7% and 70.6%, respectively, of the segment gross margin in our Gathering and Processing segment.

If the current decline in commodity prices is prolonged, it could result in a decrease in exploration and development activities in the fields served by our gathering and pipeline transmission systems and our natural gas processing plants, which could lead to reduced utilization of these assets. During periods of natural gas price decline and/or if the price of NGLs and crude oil declines, the level of drilling activity could decrease. When combined with a reduction of cash flow resulting from lower commodity prices, a reduction in our producers' borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers' spending for natural gas drilling activity, which could result in lower volumes being transported on our gathering and transmission systems.

Our hedging activities may not be effective in reducing our direct exposure to commodity price risk and may, in certain circumstances, increase the variability of our cash flows.

We have entered into derivative transactions related to only a portion of the equity volumes of NGLs to which we take title. As a result, we will continue to have direct commodity price risk to the unhedged portion of our NGL equity volumes. We currently have no hedges in place beyond June 2015. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our liquidity. The derivative instruments we utilize for these hedges are based on posted market prices, which may be lower than the actual NGL prices that we realize in our operations. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and, in certain circumstances, may actually increase the variability of our cash flows. To the extent we hedge our commodity price risk, we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. Further, there may be times where we terminate or enter into offsetting positions depending on our view of future market prices. We do not enter into derivative transactions with respect to the volumes of natural gas or condensate that we purchase and sell.

We may not successfully balance our purchases and sales of natural gas, which would increase our exposure to commodity price risks.

We purchase from producers and other suppliers a substantial amount of the natural gas that flows through our pipelines and processing facilities for sale to third parties, including natural gas marketers and other purchasers. We are exposed to fluctuations in the price of natural gas through volumes sold pursuant to percent-of-proceeds arrangements as well as through volumes sold pursuant to our fixed-margin contracts.

In order to mitigate our direct commodity price exposure, we do not enter into natural gas hedge contracts, but rather attempt to balance our natural gas sales with our natural gas purchases on an aggregate basis across all of our systems. We may not be successful in balancing our purchases and sales, and as such may become exposed to fluctuations in the price of natural gas. For example, we are currently net purchasers of natural gas on certain of our systems and net sellers of natural gas on certain of our other systems. Our overall net position with respect to natural gas can change over time and our exposure to fluctuations in natural gas prices could materially increase, which in turn could result in increased volatility in our revenue, gross margin and cash flows.

Although we enter into back-to-back purchases and sales of natural gas in our fixed-margin contracts in which we purchase natural gas from producers or suppliers at receipt points on our systems and simultaneously sell an identical volume of natural gas at delivery points on our systems, we may still be exposed to commodity price risks. For example, the volumes or timing of our purchases and sales may not correspond. In addition, a producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to become unbalanced. If our purchases and sales are unbalanced, we will face increased exposure to commodity price risks, which in turn could result in increased volatility in our revenue, gross margin and cash flows.

A decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining or heating industries, could adversely affect the profitability of our midstream business.

Various factors impact the demand for natural gas, NGLs and condensate, including general economic conditions, extended periods of ethane rejection, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, availability of natural gas processing and transportation capacity and government regulations affecting prices and production levels of natural gas, NGLs and condensate. A decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining or heating industries, could adversely affect the profitability of our midstream business.

We are a relatively small enterprise, and our management has limited history and experience with our specific assets. As a result, operational, financial and other events in the ordinary course of business could disproportionately affect us, and our ability to grow our business could be significantly limited.

We may be smaller than many of the other companies in our industry for the foreseeable future, not only in terms of market capitalization but also in terms of managerial, operational and financial resources. Consequently, an operational incident, customer loss or other event that would not significantly impact the business and operations of the larger companies in our industry may have a material adverse impact on our business and results of operations. In addition, our executive management team is relatively small with limited experience in managing our specific business and assets. As a result, we may not be able to anticipate or respond to material changes or other events in our business as effectively as if our executive management team had extensive experience and had managed our business and assets for many years. Furthermore, acquisitions and other growth projects may place a significant strain on our management resources. As a result, our ability to execute our growth strategy and to integrate acquisitions and expansion projects successfully into our existing operations could be significantly limited.

We have identified material weaknesses in our internal control over financial reporting, and our business and unit price may be adversely affected if we do not adequately address those weaknesses or if we have other material weaknesses or significant deficiencies in our internal control over financial reporting.

We identified material weaknesses in our internal control over financial reporting related to an entity acquired in 2013. We determined that we did not design and maintain effective controls related to certain process-level activities of the newly acquired entity that contributed to material weaknesses related to: i) the precision of the review of supporting documentation regarding the existence and occurrence of condensate revenues and ii) the omission of a control to validate whether the measurement input agreed to supporting documentation regarding the completeness and accuracy of data used in calculation of lost and unaccounted for pipeline liquids. The existence of these or one or more other material weaknesses or significant deficiencies could result in errors in our financial statements, and substantial costs and resources may be required to rectify any internal control deficiencies. Although the material weaknesses above have been remediated as of December 31, 2014, if we cannot produce reliable financial reports, investors could lose confidence in our reported financial information, the market price of our units could decline significantly, we may be unable to obtain additional financing to operate and expand our business and our business and financial condition could be harmed.

We continue to evaluate the adequacy of our accounting personnel staffing level and other matters related to our internal controls over financial reporting, and we cannot predict the outcome of this evaluation of the effectiveness of our internal controls over financial reporting.

Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm's future conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to implement and maintain effective internal controls over financial reporting will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

We depend on a relatively small number of customers for a significant portion of our gross margin. The loss of any one of these customers could adversely affect our ability to make distributions.

A significant percentage of the gross margin in each of our segments is attributable to a relatively small number of customers. Additionally, a number of customers upon which our business depends are small companies that may in the future have limited access to capital or that may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better capitalized companies. For information regarding our concentration of customers and associated credit risk by segment, please refer to Part I, Item 1. Business in this Annual Report. Although we have gathering, processing and transmission contracts with significant customers of varying duration and commercial terms, if one or more of these customers were to default on their contract or if we were unable to renew our contract with one or more of these customers on favorable terms, we may not be able to replace these customers in a timely fashion, on favorable terms or at all. In any of these situations, our gross margin and cash flows and our ability to make cash distributions to our unitholders may be adversely affected. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our gross margin.

Our reliance on our key customers exposes us to their credit risks, and any material nonpayment or nonperformance by our key customers or purchasers could have a material adverse effect on our revenue, gross margin and cash flows.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers to which we provide services and sell commodities. For the year ended December 31, 2014, our Gathering and Processing segment derived 33% and 12% of its revenue from ConocoPhillips and Shell, respectively. For the year ended December 31, 2013, our Gathering and Processing segment derived 43% and 19% of its revenue from ConocoPhillips and Shell, respectively. Additionally, ExxonMobil and Enbridge Marketing (US) L.P. are the two largest purchasers of natural gas and transmission capacity, respectively, in our Transmission segment and accounted for approximately 43% and 16%, respectively, of our segment revenue for the year ended December 31, 2014 and ExxonMobil and Enbridge Marketing (US) L.P. approximately 39% and 16%, respectively, of our segment revenue for the year ended December 31, 2013. In our Terminals segment, Shell and Shrieve Oilfield Products Group accounted for 20% and 19%, respectively, for the year ended December 31, 2014 and 17% and 20%, respectively, for the year ended December 31, 2013.

Some of our customers and purchasers may be highly leveraged or under-capitalized and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us. In addition, some of our customers, such as Calpine Corporation, which emerged from bankruptcy in 2008, may have a history of bankruptcy or other material financial and liquidity issues. Any material nonpayment or nonperformance by any of our key customers or purchasers could have a material adverse effect on our revenue, gross margin and cash flows and our ability to make cash distributions to our unitholders.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution could be adversely affected.

Our natural gas gathering and processing and transportation systems connect to other pipelines or facilities, the majority of which, such as the Southern Natural Gas Company, or Sonat, pipeline, the Toca plant, oil gathering lines on Quivira and the Burns Point processing plant, as well as the Destin, Tennessee Gas and Transco pipelines, are owned and operated by third parties. For example, our elective processing arrangements are entirely dependent on the Toca plant for processing services and the Sonat pipeline for natural gas takeaway capacity and are substantially dependent on Kinetica for natural gas supply volumes. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. If any of these pipelines or other midstream facilities becomes unable to receive or transport natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution could be adversely affected.

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

We gather, purchase, process, transport and sell most of the natural gas and NGLs on our systems under contracts with terms of various durations. We provide above-ground storage services at our marine terminals that support various commercial customers. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with percent-of-proceeds contracts may choose to switch to fee-based gathering and transportation contracts, or a producer with whom we have a natural gas purchase contract may choose to enter into a transportation contract with us and retain title to its natural gas. To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenue, gross margin and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected.

Increased regulation of hydraulic fracturing could result in reductions, delays or increased costs in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate production. While the underground injection of fluids is regulated by the U.S. EPA under the Safe Drinking Water Act ("SDWA"), fracturing is excluded from regulation unless the injection fluid is diesel fuel. EPA has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. The EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, the EPA may propose regulations in 2015 under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult for our customers to complete oil and natural gas wells in shale formations and increase their costs of compliance. In addition, the EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer's costs and decrease their levels of production. On May 4, 2012, the federal Bureau of Land Management announced draft rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands; a revised rule was released for public comment on May 25, 2013 and is under review by the Office of Management and Budget. Moreover, in late 2011, the EPA announced that it is developing standards for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and indicated that such standards would be proposed in 2015. The adoption and implementation of rules relating to hydraulic fracturing could result in increased expenditures for our natural gas exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.

We compete with other midstream companies in our areas of operation. In addition, some of our competitors are large companies that have greater financial, managerial and other resources than we do. Our competitors may expand or construct gathering, compression, treating, processing, transportation or terminaling systems that would create additional competition for the services we provide to our customers. In addition, our customers may develop their own gathering, compression, treating, processing or transportation systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Significant portions of our pipeline systems have been in service for several decades and we have a limited ownership history with respect to all of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Significant portions of the pipeline systems that we purchased had been in service for many decades prior to our purchase. Consequently, our executive management team has a limited history of operating such assets. There may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems could adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

We may incur significant costs and liabilities as a result of safety regulation, including pipeline integrity management program testing and related repairs.

Pursuant to the PSIA, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could harm "high consequence areas," including high population areas, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators, including us, to:

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

In addition, many states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. Although many of our natural gas facilities fall within a class that is not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with our non-exempt pipelines, particularly our AlaTenn and Midla pipelines. We currently estimate that we will incur future costs of approximately $1.1 million during 2015 to complete the testing required by existing DOT regulations. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, should we fail to comply with DOT regulations, we could be subject to penalties and fines.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In addition, PHMSA has published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements or to include additional pipelines in "high consequence areas." Such legislative and regulatory changes could have a material effect on our operations and costs of transportation services.

Recent spills and their aftermath could lead to additional governmental regulation of the offshore exploration and production industry, which may result in substantial cost increases or delays in our offshore natural gas gathering activities.

In April 2010, a deep-water exploration well located in the Gulf of Mexico, owned and operated by companies unrelated to us, sustained a blowout and subsequent explosion leading to the leaking of hydrocarbons. In response to this event, certain federal agencies and governmental officials ordered additional inspections of deep-water operations in the Gulf of Mexico. This spill and its aftermath has led to additional governmental regulation of the offshore exploration and production industry and delays in the issuance of drilling permits, which may result in volume impacts, cost increases or delays in our offshore natural gas gathering activities, which could materially impact our offshore operations, and our business, financial condition and results of operations. We cannot predict with any certainty what form any additional regulation or limitations will take.

We intend to grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms from third parties, our future growth may be limited, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our ability to grow our operations and increase our distributions to our unitholders.

If we are unable to make accretive acquisitions from third parties, whether because we are i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, ii) unable to obtain financing for these acquisitions on economically acceptable terms or iii) outbid by competitors or for any other reason, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per unit basis.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue and costs, including synergies;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;
- an inability to integrate successfully the assets or businesses we acquire, particularly given the relatively small size of our management team and its limited history with our assets;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas and business lines; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

If we are unable to timely and successfully integrate our acquisitions, our future financial performance may suffer, and we may fail to realize all of the anticipated benefits of the transaction.

Our future growth may depend in part on our ability to integrate our acquisitions. We cannot guarantee that we will successfully integrate any acquisitions into our existing operations, or that we will achieve the desired profitability and anticipated results from such acquisitions. Failure to achieve such planned results could adversely affect our operations and cash flows available for distribution to our unitholders.

The integration of acquisitions with our existing business involves numerous risks, including:

- operating a significantly larger combined organization and integrating additional midstream operations into our existing operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management's attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- integrating personnel from diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities, including those under the same stringent environmental laws and regulations relating to releases of pollutants into the environment and environmental protection as are applicable to our existing plants, pipelines and facilities. If so, our operation of these new assets could cause us to incur increased costs to address these liabilities or to attain or maintain compliance with such requirements. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we may consider in determining the application of these funds and other resources.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through organic growth projects. The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political, legal and economic uncertainties that are beyond our control. Such expansion projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Cost overruns on construction projects may cause unexpected changes in project economics. Moreover, our revenue may not increase immediately upon the expenditure of funds on a particular project.

For instance, if we expand a pipeline, the construction may occur over an extended period of time, yet we will not receive any material increases in revenue until the project is completed and placed into service. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize or only materializes over a period materially longer than expected. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

In addition, the construction of additions to our existing gathering and transportation assets, or the construction of new gathering and transportation assets, may require us to obtain new rights-of-way. We may be unable to obtain such rights-of-way and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases materially, our cash flows could be adversely affected.

In connection with our expansion capital programs, we have agreed to construct oil and gas gathering pipelines to service existing and future oil and gas properties, which involves potential risks.

In connection with our expansion capital programs, we may agree, at our cost and expense, to design, acquire right-of-way for, obtain all permits from governmental authorities for, procure materials for, construct, operate, and maintain additional gathering pipelines for connection to certain current and future producing oil and gas properties. There are risks involved with such obligations, including:

- general construction cost overruns and delays resulting from numerous factors, many of which may be out of our control;
- the inability to obtain required permits for the pipelines;
- the inability to obtain rights-of-way for the gathering pipelines, which may result in pipelines being re-routed, which itself could result in cost overruns and delays;
- the risk associated with producer's exploration and production activities and the associated potential failure of the gathering pipelines to generate attractive cash flows given our obligation to construct and operate them; and
- title issues or environmental or regulatory compliance matters or liabilities or accidents associated with the construction or operation of the pipelines.

We currently expect to fund these costs with borrowings under our credit facility. If we are unable to finance the expansion costs with existing liquidity, we could be required to seek alternative sources of liquidity, which could be costly or may not be available. In the event expansion and extension of the oil and gas properties is significantly more expensive than we expect or we are unable to obtain financing for such construction, it could have a material adverse effect on our financial condition, including our results of operations and cash flows.

We do not intend to obtain independent evaluations of natural gas reserves connected to our gathering and transportation systems on a regular or ongoing basis; therefore, in the future, volumes of natural gas on our systems could be less than we anticipate.

We do not intend to obtain independent evaluations of natural gas reserves connected to our systems on a regular or ongoing basis. Accordingly, we may not have independent estimates of total reserves dedicated to some or all of our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering and transportation systems are less than we anticipate and we are unable to secure additional sources of natural gas, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured, our operations and financial results could be adversely affected.

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

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

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

Our interstate natural gas pipelines are subject to regulation by the FERC, which could adversely affect our ability to make distributions to our unitholders.

Our AlaTenn and Midla interstate natural gas transportation systems are subject to regulation by the FERC, under the NGA. Under the NGA, the rates for and terms of conditions of service on these interstate facilities must be just and reasonable and not unduly discriminatory. The rates and terms and conditions for our interstate pipeline services are set forth in tariffs that must be filed with and approved by the FERC. Pursuant to the FERC's jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenue associated with providing transportation service.

Under the NGA, the FERC has the authority to regulate companies that provide natural gas pipeline transportation services in interstate commerce. The FERC's authority over such companies includes such matters as:

- rates, terms and conditions of service;
- the types of services interstate pipelines may offer to their customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

The EP Act 2005 amended the NGA to add an anti-manipulation provision. Pursuant to the amended NGA, the FERC established rules prohibiting energy market manipulation. Also, the FERC's rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transportation employees function independently of marketing employees. We are subject to audit by the FERC of our compliance in general, including adherence to all its rules and regulations. A violation of these rules, or any other rules, regulations or orders issued or administered by the FERC, may subject us to civil penalties, disgorgement of certain profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the EP Act 2005 amended the NGA and the NGPA, to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1.0 million per day per violation.

Additionally, existing rates may not reflect our current costs of operations, which may have risen since the last time our rates were approved by the FERC.

The application of certain FERC policy statements could affect the rate of return on our equity that we are allowed to recover through rates and the amount of any allowance our interstate systems can include for income taxes in establishing their rates for service, which would in turn impact our revenue and/or equity earnings.

In setting authorized rates of return for interstate natural gas pipelines, the FERC uses a discounted cash flow model that incorporates the use of proxy groups to develop a range of reasonable returns earned on equity interests in companies with corresponding risks. The FERC then assigns a rate of return on equity within that range to reflect specific risks of that pipeline when compared to the proxy group companies. The FERC allows master limited partnerships ("MLPs"), to be included in the proxy group to determine return on equity. However, as to such MLPs, the FERC will generally adjust the long-term growth rate used to calculate the equity cost of capital. The FERC stated that the long-term growth projection for natural gas pipeline MLPs will be equal to fifty percent of gross domestic product ("GDP"), as compared to the unadjusted GDP used for corporations. Therefore, to the extent that MLPs are included in a proxy group, the FERC's policy lowers the return on equity that might otherwise be allowed if there were no adjustment to the MLP growth projection used for the discounted cash flow model. This could lower the return on equity that we would otherwise be able to obtain.

The FERC currently allows partnerships, including MLPs, to include in their cost-of-service an income tax allowance if the partnership's owners have actual or potential income tax liability, a matter that will be reviewed by the FERC on a case-by-case basis. Any changes to the FERC's treatment of income tax allowances in cost-of-service rates or an adverse determination with respect to the inclusion of an income tax allowance in our interstate pipelines' rates could result in an adjustment in a future rate case of our interstate pipelines' respective equity rates of return that underlie their recourse rates and may cause their recourse rates to be set at a level that is different, and in some instances lower, than the level otherwise in effect.

A change in the jurisdictional characterization or regulation of our assets by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets which could materially and adversely affect our financial condition, results of operations and cash flows.

Intrastate transportation facilities that do not provide interstate transmission services are exempt from the jurisdiction of the FERC under the NGA. Although the FERC has not made any formal determinations with respect to any of our facilities, we believe that our intrastate natural gas pipelines and related facilities that are not engaged in providing interstate transmission services are engaged in exempt gathering and intrastate transportation and, therefore, are not subject to FERC jurisdiction. We believe that our natural gas gathering pipelines meet the traditional tests that the FERC has used to determine if a pipeline is a gathering pipeline and is therefore not subject to the FERC's jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, the FERC's policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and intrastate transportation and gathering facilities, on the other, is a fact-based determination made by the FERC on a case-by-case basis. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by the FERC.

Moreover, FERC regulation affects our gathering, transportation and compression business generally. The FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, capacity release and market transparency and market center promotion, directly and indirectly affect our gathering business. In addition, the classification and regulation of our gathering and intrastate transportation facilities also are subject to change based on future determinations by the FERC, the courts or Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC's efforts to promote open access, transparency, and the unbundling of interstate pipeline services has prompted a number of interstate pipelines to transfer their non-jurisdictional gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. Such additional scrutiny could result in increased expenses to us and a resulting materially adverse change in our finances.

We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our natural gas gathering, compression, treating and transportation operations are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the federal CERCLA and analogous state laws that regulate the cleanup of hazardous substances that may be or have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;
- the federal Clean Water Act and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the federal OPA and analogous state laws that establish strict liability for releases of oil into waters of the United States;
- the federal RCRA and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities;
- the ESA; and
- the Toxic Substances Control Act ("TSCA"), and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations. Numerous governmental authorities, such as the EPA, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations.

In addition, we may experience a delay in obtaining or be unable to obtain required permits, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue. Please read "Business - Environmental Matters - Air Emissions" for more information about these matters.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbon wastes and potential emissions and discharges related to our operations. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hydrocarbon wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. We may not be able to recover all or any of these costs from insurance. In addition, changes in environmental laws occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. Please read "Business - Environmental Matters" for more information.

We may be unable to obtain or renew permits necessary for our operations or the operations we may acquire in future acquisitions.

Our facilities operate under a number of required federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approvals, limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval, limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay issuing a new or renewed material permit, license or approval, or to revoke or substantially modify an existing permit, license or approval, could have a material adverse effect on our financial condition, including our results of operations and cash flows.

Our operations may impact the environment or cause environmental contamination, which could result in material liabilities to us.

Our operations use hazardous materials, generate limited quantities of hazardous wastes and may affect runoff or drainage water. In the event of environmental contamination or a release of hazardous materials, we could become subject to claims for toxic torts, natural resource damages and other damages and for the investigation and cleanup of soil, surface water, groundwater, and other media. Such claims may arise out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share. These and other impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could have a material adverse effect on us. Please read "Business - Environmental Matters" for more information.

Climate change legislation could result in increased operating costs and reduced demand for the natural gas services we provide.

In recent years, the U.S. Congress has been considering legislation to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane, which are understood to contribute to global warming. The American Clean Energy and Security Act of 2009, passed by the House of Representatives, would, if enacted by the full Congress, have required GHG emissions reductions by covered sources of as much as 17% from 2005 levels by 2020 and by as much as 83% by 2050. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories 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 gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that smaller sources such as our gas-fired compressors could become subject to GHG-related regulation. Depending on the particular program, we could be required to control emissions or to purchase and surrender allowances for GHG emissions resulting from our operations.

The EPA could develop new rules and current rules may be modified.

Independent of Congress, the EPA is beginning to adopt regulations controlling GHG emissions under its existing Clean Air Act authority. For example, on December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human 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 by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In 2009, the EPA adopted rules regarding regulation of GHG emissions from motor vehicles. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. Our Bazor Ridge facility is currently required to report under this rule. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of greenhouse gas emissions by regulated facilities to the EPA annually. EPA proposed to update these rules in December 2014 to add gathering and boosting facilities and blowdowns of natural gas transmission pipelines to the list of covered facilities under the GHG reporting rule. We filed emission reports for our Bazor Ridge and Chatom systems in March 2012. The Supreme Court overturned EPA’s 2010 Tailoring Rule to the extent it imposes a requirement to obtain air permits based solely on emissions of GHG, though EPA still may require installation of GHG controls on large sources of other air pollutants. As discussed in the climate change section above, EPA also has initiated regulation of methane from oil and gas facilities. Final rules are expected in 2016. It is likely that we will be required to control methane emissions from new or modified facilities under this rulemaking.

On August 16, 2012, the EPA published final rules that establish new air emission controls for natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), and a separate set of emission standards to address hazardous air pollutants frequently associated with natural gas processing activities. The rules establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants. Under these rules we are required to modify some of our operations, though we do not expect these modifications to have a material effect on our operations. Following the publication of the final rule, the EPA received petitions for reconsideration of certain aspects of the standards. On April 12, 2013, the EPA published proposed updates to the NSPS Section OOOO storage tank requirements. On September 23, 2013, the EPA published final revisions to the NSPS Section OOOO storage tank requirements, including a phase-in of installation of VOC controls and alternate limits for tanks where emissions have declined. Finally, in December 2014 EPA issued revised definitions related to the stages of well completions and amended storage tank requirements under NSPS Section OOOO. EPA continues to reconsider other portions of Section OOOO.

Although it is not possible at this time to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the natural gas we gather, treat or otherwise handle in connection with our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of greenhouse gases could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas, resulting in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Our pipelines may become subject to more stringent safety regulation.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The Department of Transportation DOT, has also recently proposed legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules, which is in addition to the Pipeline and Hazardous Materials Safety Administration's announced intention to strengthen its rules. The PHMSA, which is part of DOT, recently issued a final rule, effective October 1, 2011, applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. While we believe that this rule does not apply to any of our pipelines, we cannot predict the outcome of other proposed legislative or regulatory initiatives. Such legislative and regulatory changes could have a material effect on our operations particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines not previously subject to such requirements. Additionally, legislative and regulatory changes may also result in higher penalties for the violation of federal pipeline safety regulations and the costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the costs of compliance associated with such requirements.

The adoption and implementation of new statutory and regulatory requirements for swap transactions could have an adverse impact on our ability to hedge risks associated with our business.

We hedge a portion of our commodity risk and our interest rate risk. The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including businesses like ours, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or Act, was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Act, the CFTC adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in Federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC had filed a notice of appeal with respect to this ruling but on October 29, 2013 voted to voluntarily dismiss this appeal. On November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. Comments on these new rules were due in early January 2014, and, as these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. Under the rules adopted by the CFTC, we believe our hedging transactions will qualify for the non-financial, commercial end user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement. The Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging 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 fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore 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 our business, our financial condition, and our results of operations.

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

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

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

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

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

We currently have a small management team, who does not devote 100% of their time to us. Our ability to operate our business effectively could be impaired if we fail to attract and retain key management personnel.

We currently have a small management team, and our ability to operate our business and implement our strategies depends on the continued contributions of certain executive officers and key employees of our General Partner. Our General Partner has a smaller managerial, operational and financial staff than many of the companies in our industry. Given the small size of our management team, the loss of any one member of our management team could have a material adverse effect on our business. In addition, certain of our field operating managers are approaching retirement age. Our management team devotes a portion of its efforts to projects owned and operated by our General Partner, which means they are not devoted 100% of their time to the Partnership. We believe that our future success will depend on our continued ability to attract and retain highly skilled management personnel with midstream natural gas industry experience and hiring for such persons in the midstream natural gas industry is competitive. Given our small size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate our business.

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

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

Our work force could become unionized in the future, which could adversely affect the stability of our production and materially reduce our profitability.

All of our systems are operated by non-union employees. Our employees have the right at any time under the National Labor Relations Act to form or affiliate with a union. If our employees choose to form or affiliate with a union and the terms of a union collective bargaining agreement are significantly different from our current compensation and job assignment arrangements with our employees, these arrangements could adversely affect the stability of our operations and materially reduce our profitability.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may adversely affect our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational, or other data processing systems fail or have other significant shortcomings or downtime, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operational departments, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our business. In addition, cyber-attacks on our customer and employee data may result in financial loss and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

Our assets and operations can be affected by weather, weather related conditions and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightning, cold weather and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss and in some instances, we have been unable to obtain insurance on some of our assets on commercially reasonable terms, if at all. If we incur a significant disruption in our operations or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

Terrorist attacks, the threat of terrorist attacks, and sustained military campaigns may adversely impact our results of operations.

Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East and North Africa or other sustained military conflicts may affect our operations in unpredictable ways, including disruptions of crude oil supplies or storage facilities, and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Global economic conditions may have adverse impacts on our business and financial condition.

Changes in economic conditions could adversely affect our financial condition and results of operations. A number of economic factors, including, but not limited to, gross domestic product, consumer interest rates, reduced government spending, strength of U.S. currency versus other international currencies, consumer confidence and debt levels, retail trends, inflation and foreign currency exchange rates, may generally affect our business. Recessionary economic cycles, higher unemployment rates, higher fuel and other energy costs and higher tax rates may adversely affect demand for natural gas and NGLs. Also, any tightening of the capital markets could adversely impact our ability to execute our long-term organic growth projects and meet our obligations to our producer customers and limit our ability to raise capital and, therefore, have an adverse impact on our ability to otherwise take advantage of business opportunities or react to changing economic and business conditions. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

Risks Related to Our Units, Corporate Structure and Ownership

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

The partnership is a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than equity in our subsidiaries and equity investees. As a result, our ability to make distributions depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit instruments, applicable state business organization laws and other laws and regulations.

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

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

As our common units are yield-oriented securities, increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

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

HPIP, an affiliate of ArcLight Capital Partners, and AIM Midstream Holdings directly own our General Partner, which has sole responsibility for conducting our business and managing our operations. HPIP elects all of the members of the board of our General Partner. HPIP, AIM Midstream Holdings and our General Partner have conflicts of interest with us and limited fiduciary duties, and they may favor their own interests to the detriment of us and our unitholders.

HPIP and AIM Midstream Holdings own our General Partner. HPIP has the power to appoint all of the officers and directors of our General Partner, some of whom are also officers of HPIP. The directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner that is beneficial to it, and have no duty to us or our common unitholders. Conflicts of interest may arise between HPIP and AIM Midstream Holdings and our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of HPIP and AIM Midstream Holdings over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires HPIP or AIM Midstream Holdings to pursue a business strategy that favors us;
- our partnership agreement limits the liability of and reduces the fiduciary duties owed by our General Partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of such fiduciary duty;
- except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval;
- our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our General Partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our

unitholders and to our General Partner and the ability of the Series A convertible preferred units to convert to common units;

- our General Partner determines which costs incurred by it are reimbursable by us;
- our General Partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the Series A convertible preferred units or Series B Units , to make incentive distributions or to accelerate the expiration of a subordination period;
- our partnership agreement permits us to classify up to $11.5 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our Series A convertible preferred units and Series B Units or to our General Partner in respect of the General Partner interest or the incentive distribution rights;
- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our General Partner intends to limit its liability regarding our contractual and other obligations;
- our General Partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;
- our General Partner controls the enforcement of the obligations that it and its affiliates owe to us;
- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our General Partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our General Partner's incentive distribution rights without the approval of the Conflicts Committee of the board of directors of our General Partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

HPIP and AIM Midstream Holdings are not limited in their ability to compete with us and are not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

HPIP and AIM Midstream Holdings are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, HPIP and AIM Midstream Holdings may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities. Moreover, while HPIP and AIM Midstream Holdings may offer us the opportunity to buy additional assets from them, they are under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed.

The New York Stock Exchange ("NYSE") does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

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

If you are not an eligible holder, you may not receive distributions or allocations of income or loss on your common units and your common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are U.S. individuals or entities subject to such taxation. If you are not an eligible holder, our General Partner may elect not to make distributions or allocate income or loss on your units, and you run the risk of having your units redeemed by us at the lower of your purchase price cost and the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Common units held by persons who are non-taxpaying assignees will be subject to the possibility of redemption.

Our partnership agreement gives our General Partner the power to amend the agreement to avoid any adverse effect on the maximum applicable rates chargeable to customers by us under FERC regulations or to reverse an adverse determination that has occurred regarding such maximum rate. If our General Partner determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us, then our General Partner may adopt such amendments to our partnership agreement as it determines are necessary or advisable to obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant) and permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our General Partner to obtain proof of the U.S. federal income tax status.

Our General Partner intends to limit its liability regarding our obligations.

Our General Partner intends to continue limiting its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our General Partner or its assets. Our General Partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our General Partner. Our partnership agreement provides that any action taken by our General Partner to limit its liability is not a breach of our General Partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our General Partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

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

We distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, and in our credit facility, on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement limits our General Partner's fiduciary duties to us and the holders of our common units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner or otherwise, free of fiduciary duties to us and our unitholders. This entitles our General Partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels; and

- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

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

- provides that whenever our General Partner makes a determination or takes, or declines to take, any other action in its capacity as our General Partner, our General Partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

- provides that our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as such decisions are made in good faith, meaning that it believed that the decision was in, or not opposed to, the best interest of our partnership;
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that our General Partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

a. approved by the Conflicts Committee of the board of directors of our General Partner, although our General Partner is not obligated to seek such approval;
b. approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates;
c. on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
d. fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our General Partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the Conflicts Committee, and the board of directors of our General Partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

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

Our General Partner has the right, at any time it has received incentive distributions exceeding the target distribution described in our partnership agreement for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election by our General Partner, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

We anticipate that our General Partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our General Partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our General Partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our General Partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the General Partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our General Partner in connection with resetting the target distribution levels related to our General Partner's incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The board of directors of our General Partner will be chosen by HPIP. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they cannot currently remove our General Partner without its consent.

Our unitholders are unable to remove our General Partner without its consent because our General Partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our General Partner. As of March 6, 2015, HPIP owns 5,909,349 Series A convertible preferred units and controls our General Partner which holds 1,277,772 Series B Units which, if both were converted one-for-one, would represent 24.0% of our then-outstanding common units. AIM Midstream Holdings owns 2.8% of our outstanding limited partner units.

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

Unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, cannot vote on any matter.

Our General Partner interest or the control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its General Partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of HPIP to transfer all or a portion of their ownership interest in our General Partner to a third party. The new owner of our General Partner would then be in a position to replace the board of directors and officers of our General Partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because of the Series A convertible preferred units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

As of March 6, 2015, HPIP holds 5,909,349 Series A convertible preferred units. The Series A convertible preferred units are convertible into common units at the election of HPIP at any time after January 1, 2014. In addition, HPIP and AIM Midstream Holdings control our General Partner, which holds 1,277,772 Series B Units, which will convert into common units on a one-for-one basis on January 31, 2016. AIM Midstream Holdings currently holds an aggregate of 626,304 common units. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

If at any time our General Partner and its affiliates own more than 80% of the common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of March 6, 2015, HPIP owns 5,909,349 Series A convertible preferred and controls our General Partner which holds 1,277,772 Series B Units which, if both were converted one-for-one, would represent 24.0% of our then-outstanding common units. AIM Midstream Holdings owns 2.8% of our outstanding limited partner common units.

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

A General Partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the General Partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a General Partner if a court or government agency were to determine that:

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

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price
of our common units and could have a material adverse effect on our business.

Our assets include a 50% non-controlling interest in the Burns Point System and a 66.7% non-controlling interest in Main Pass Oil Gathering, LP, which may be deemed to be "investment securities" within the meaning of the Investment Company Act of 1940. In the future, we may acquire additional minority owned interests in joint ventures that could be deemed "investment securities." If a sufficient amount of our assets are deemed to be "investment securities" within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights 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 or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be subject to federal income tax at the corporate tax rate, significantly reducing the cash available for distributions. Additionally, distributions to our unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be "investment securities."

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service, or the IRS were to treat us as a corporation for federal income tax purposes, or we become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to the unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we will be treated as a corporation, the IRS could disagree with the positions we take or a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to a unitholder would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to the unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation for federal tax purposes would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

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

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception that allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of the U.S. Congress have considered, and the President's Administration has proposed, substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such change could negatively impact the value of an investment in our common units.

Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay the State of Texas a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Imposition of such a tax on us by other states would reduce the cash available for distribution to a unitholder. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

Changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state, local and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures or impact our utilization of net operating losses. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties. The costs of these audits are borne indirectly by the unitholders and our general partner because such costs reduce our cash available for distribution.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. We have, however, received a Notice of Beginning of Administrative Proceeding from the IRS. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS, and the outcome of any such contest, may increase a unitholder's tax liability and result in adjustment to items unrelated to us and could materially and adversely impact the market for our common units and the price at which they trade. The rights of a unitholder owning less than a 1% profits interest in us to participate in the federal income tax audit process are very limited. In addition, our costs of any contest with the IRS will be borne indirectly by the unitholders and our general partner because such costs will reduce our cash available for distribution.

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

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

Certain actions that we may take, such as issuing additional units, may increase the federal income tax liability of unitholders.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder's share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder's units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder's tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to the our assets.

There are limits on the deductibility of losses that may adversely affect unitholders.

In the case of taxpayers subject to the passive loss rules (generally, individuals, closely-held corporations and regulated investment companies), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of the unitholder's entire investment in us in a fully taxable transaction with an unrelated party. A unitholder's share of our net passive income may be offset by unused losses from us carried over from prior years, but not by losses from other passive activities, including losses from other publicly traded partnerships.

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

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

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

Investment in common units by tax-exempt entities, such as individual retirement accounts, or IRAs, other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income, which may be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

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

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

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

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

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and such unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their common units.

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

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

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

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

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination, among other things, would result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedule K-1's if relief from the IRS was not granted, as described below) for one calendar year. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Under current law, such a termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure for publicly traded partnerships that terminate in this manner, whereby, if a publicly traded partnership that has terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years resulting from the termination.

Unitholders may be subject to state and local taxes and return filing requirements in states and jurisdictions where they do not reside as a result of investing in our units.

In addition to federal income taxes, unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if the unitholders do not live in any of those jurisdictions. Unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder's responsibility to file all U.S. federal, foreign, state, local and non-U.S. tax returns. Our outside tax counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

Some of the states in which we do business or own property may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the state, generally does not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

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A description of our properties is contained in "Item 1. Business" of this Annual Report and incorporated into this Item 2. by reference.

Our principal executive offices are located at 1400 16th Street, Suite 310, Denver, CO 80202 and our telephone number is 720-457-6060.

Item 3. Legal Proceedings

We are not currently party to any pending litigation or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate impact of any proceedings cannot be predicted with certainly, our management believes that the resolution of any of our pending proceeds will not have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosure

Not applicable.

PART II

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

Market Information

Our common units have been listed on the New York Stock Exchange since July 27, 2011, under the symbol "AMID." The following table sets forth the high and low sales prices of our common units, as reported by the New York Stock Exchange ("NYSE") for each quarter during 2014 and 2013, together with distributions paid subsequent to each quarter for that quarter through December 31, 2014:

| Period Ended | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
|---|---|---|---|---|
| 2014 | | | | |
| High Price | $29.65 | $32.01 | $30.52 | $28.95 |
| Low Price | $18.22 | $27.86 | $25.39 | $22.62 |
| Distribution per common unit | $0.4725 | $0.4725 | $0.4625 | $0.4625 |
| 2013 | | | | |
| High Price | $28.80 | $22.60 | $23.00 | $18.89 |
| Low Price | $17.51 | $18.71 | $15.65 | $13.74 |
| Distribution per common unit | $0.4525 | $0.4525 | $0.4325 | $0.4325 |

As of March 6, 2015, there were 56 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. We have also issued approximately 5,909,349 Series A convertible preferred units ("Series A Units"), 1,277,772 Series B convertible units ("Series B Units") and 392,261 General Partner units, for which there is no established trading market. The holders of Series B units share in distributions from the Partnership on a pro rata basis with the holders of the common units. Our General Partner and its affiliates receive quarterly distributions on the General Partner units only after the requisite distributions have been paid on the common, Series A preferred units and Series B Units.

Our Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects our belief that our unitholders will be better served if we distribute rather than retain our available cash. Generally, our available cash is the sum of our i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and ii) cash on hand resulting from working capital borrowings made after the end of the quarter. We pay the cash dividend in one payment to those unitholders of record on the applicable record date, as determined by the General Partner.

The following table sets forth the number of units at December 31, 2014 and 2013 (in thousands):

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Series A convertible preferred units | 5,745 | 5,279 |
| Series B convertible units | 1,255 | — |
| Limited partner common units | 22,670 | 7,414 |
| General Partner units | 392 | 185 |

Our General Partner's initial 2.0% interest in distributions has been reduced to 1.3% due to the issuance of additional units and the General Partner has not contributed a proportionate amount of capital to us to maintain its initial 2.0% General Partner notional interest.

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our General Partner establishes in accordance with our partnership agreement as described above. We will pay our distributions on or about the 15th of each February, May, August and November to holders of record on or about the 5th of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date.

Series A Distribution Amendment

The Partnership executed an amendment (the "Amendment") to the Partnership agreement related to its outstanding Series A convertible preferred units ("Series A Units") which became effective July 24, 2014. As a result of the Amendment, distributions on Series A Units will be made with paid-in-kind Series A Units, cash or a combination thereof, at the discretion of the Board of Directors, which began with the distribution for the three months ended June 30, 2014 and will continue through the distribution for the quarter ended March 31, 2015. Prior to the Amendment, the Partnership was required to pay distributions on the Series A Units with a combination of paid-in-kind units and cash. At December 31, 2014, we have accrued $3.2 million for the paid-in-kind Series A Units.

Item 6. Selected Historical Financial and Operating Data

The following table presents selected historical consolidated financial and operating data for the periods and as of the dates indicated. We derived this information from our historical consolidated financial statements and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those consolidated financial statements and notes, which for the years 2014, 2013, and 2012 begin on F-1 to this Annual Report.

For a detailed discussion of the following table, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations."

| | Years ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 (f) | 2012 | 2011 | 2010 |
| | (in thousands, except per unit and operating data) | | | | |
| Statement of Operations Data: | | | | | |
| Revenue | $307,309 | $294,051 | $204,868 | $247,043 | $210,604 |
| Realized loss in early termination of commodity derivatives | — | — | — | (2,998) | — |
| Gain (loss) on commodity derivatives, net | 1,091 | 28 | 3,400 | (2,452) | (308) |
| Total revenue | 308,400 | 294,079 | 208,268 | 241,593 | 210,296 |
| Operating expenses: | | | | | |
| Purchases of natural gas, NGLs and condensate | 197,952 | 215,053 | 154,472 | 200,776 | 172,890 |
| Direct operating expenses | 45,702 | 32,236 | 17,183 | 11,745 | 11,302 |
| Selling, general and administrative expenses | 23,103 | 19,079 | 14,309 | 13,576 | 7,423 |
| Equity compensation expense (a) | 1,536 | 2,094 | 1,783 | 3,357 | 1,734 |
| Depreciation, amortization and accretion expense | 28,832 | 30,002 | 21,287 | 20,454 | 19,904 |
| Total operating expenses | 297,125 | 298,464 | 209,034 | 249,908 | 213,253 |
| Gain (loss) on acquisition of assets | — | — | — | 565 | — |
| Gain (loss) on involuntary conversion of property, plant and equipment | — | 343 | (1,021) | — | — |
| Gain (loss) on sale of assets, net | (122) | — | 123 | 399 | — |
| Loss on impairment of property, plant and equipment | (99,892) | (18,155) | — | — | — |

| | | | | | |
|---|---|---|---|---|---|
| Operating income (loss) | (88,739) | (22,197) | (1,664) | (7,351) | (2,957) |
| Other income (expense): | | | | | |
| Interest expense | (7,577) | (9,291) | (4,570) | (4,508) | (5,406) |
| Other expense | (670) | — | — | — | — |

| | | | | | |
|---|---|---|---|---|---|
| Earnings in unconsolidated affiliates | 348 | — | — | — | — |
| Net income (loss) before income tax benefit | (96,638) | (31,488) | (6,234) | (11,859) | (8,363) |
| Income tax (expense) benefit | (557) | 495 | — | — | — |
| Net income (loss) from continuing operations | (97,195) | (30,993) | (6,234) | (11,859) | (8,363) |
| Discontinued operations: | | | | | |
| Income (loss) from operations of disposal groups, net of tax | (611) | (2,413) | (18) | 161 | (281) |
| Net income (loss) | (97,806) | (33,406) | (6,252) | (11,698) | (8,644) |
| Net income (loss) attributable to non-controlling interests | 214 | 633 | 256 | — | — |
| Net income (loss) attributable to the Partnership | $(98,020) | $(34,039) | $(6,508) | $(11,698) | $(8,644) |
| General Partners' interest in net income (loss) | $(1,279) | $(1,405) | $(129) | $(233) | $(173) |
| Limited Partners' interest in net income (loss) | $(96,741) | $(32,634) | $(6,379) | $(11,465) | $(8,471) |
| | | | | | |
| Limited Partners' net income (loss) per common unit: | | | | | |
| Basic and diluted: | | | | | |
| Income (loss) from continuing operations | $(8.54) | $(7.15) | $(0.70) | $(1.66) | $(1.61) |
| Income (loss) from operations of disposal groups | (0.04) | (0.27) | — | 0.02 | (0.05) |
| Net income (loss) | $(8.58) | $(7.42) | $(0.70) | $(1.64) | $(1.66) |
| Weighted average number of common units outstanding: | | | | | |
| Basic and diluted (b) | 13,472 | 7,525 | 9,113 | 6,997 | 5,099 |
| Statement of Cash Flow Data: | | | | | |
| Net cash provided by (used in): | | | | | |
| Operating activities | $21,478 | $17,223 | $18,348 | $10,432 | $13,791 |
| Investing activities | (471,870) | (28,214) | (62,427) | (41,744) | (10,268) |
| Financing activities | 450,490 | 10,816 | 43,784 | 32,120 | (4,609) |
| Other Financial Data: | | | | | |
| Adjusted EBITDA (c) | $45,551 | $31,907 | $18,850 | $20,785 | $18,154 |
| Gross margin (d) | 102,807 | 74,821 | 49,431 | 44,356 | 37,405 |
| Cash distribution declared per common unit | 1.85 | 1.75 | 1.73 | 0.70 | — |
| Segment gross margin: | | | | | |
| Gathering and Processing | 50,817 | 36,985 | 36,118 | 30,619 | 23,881 |
| Transmission | 42,828 | 32,408 | 13,313 | 13,737 | 13,524 |
| Terminals | 9,162 | 5,428 | — | — | — |
| Balance Sheet Data (At Period End): | | | | | |
| Cash and cash equivalents | $499 | $393 | $576 | $871 | $63 |
| Accounts receivable and unbilled revenue | 29,543 | 29,823 | 23,470 | 20,963 | 22,850 |
| Property, plant and equipment, net | 582,182 | 312,701 | 223,819 | 170,231 | 146,808 |
| Total assets | 916,644 | 382,075 | 256,696 | 199,551 | 173,229 |

| | | | | | |
|---|---|---|---|---|---|
| Current portion of long-term debt | 2,908 | 2,048 | — | — | 6,000 |
| Long-term debt | 372,950 | 130,735 | 128,285 | 66,270 | 50,370 |

| | | | | | |
|---|---|---|---|---|---|
| Operating Data: | | | | | |
| Gathering and processing segment: | | | | | |
| Throughput (MMcf/d) | 274.8 | 277.2 | 291.2 | 250.9 | 175.6 |
| Plant inlet volume (MMcf/d) (e) | 89.1 | 117.3 | 116.1 | 36.7 | 9.9 |
| Gross NGL production (Mgal/d)(e) | 64.2 | 52.0 | 49.9 | 54.5 | 34.1 |
| Gross condensate production (Mgal/d) (e) | 75.2 | 46.2 | 22.6 | 22.6 | — |
| Transmission segment: | | | | | |
| Throughput (MMcf/d) | 778.9 | 644.7 | 398.5 | 381.1 | 350.2 |
| Firm transportation capacity reservation (MMcf/d) | 577.9 | 640.7 | 703.6 | 702.2 | 677.6 |
| Interruptible transportation throughput (MMcf/d) | 468.9 | 389.2 | 86.6 | 69.0 | 80.9 |
| Terminals segment: | | | | | |
| Storage utilization | 82.9 % | 96.2 % | — | — | — |

(a) Represents cash and non-cash costs related to our Long-Term Incentive Plan ("LTIP"). Of these amounts, $1.6 million, and $1.2 million for the years ended December 31, 2011 and 2010, respectively, were cash expenses.

(b) Includes unvested phantom units with the distribution equivalent rights ("DERs), which are considered participating securities, of 205,864 as of December 31, 2010. The DERs were eliminated on June 9, 2011. There were no such unvested phantom units with DERs at December 31, 2011, or subsequent.

(c) For a definition of adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use adjusted EBITDA to evaluate our operating performance, please read "—How We Evaluate Our Operation."

(d) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use gross margin to evaluate our operating performance, please read "— How We Evaluate Our Operations."

(e) Excludes volumes and gross production under our elective processing arrangements. For a description of our elective processing arrangements, please read "Our Operations - Gathering and Processing Segment"

(f) We acquired Blackwater Midstream Holdings, LLC ("Blackwater"), effective December 17, 2013, which is accounted for as a transaction under common control therefore these consolidated financial statements include Blackwater presented from the period April 15, 2013 through December 31, 2013.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the audited consolidated financial statements and the related notes thereto included elsewhere in this Form 10-K. Our actual results may differ materially from those anticipated in these forward-looking statements or as a result of certain factors such as those set forth below under the caption "Cautionary Statement About Forward-Looking Statements."

### Overview

We are a growth-oriented Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We are engaged in the business of gathering, treating, processing, and transporting natural gas, fractionating NGLs and storing specialty chemical products through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, three interstate pipelines, five intrastate pipelines and four marine terminal sites. We also own a 66.7% non-operating interest in MPOG, a crude oil gathering and processing system, as well as a 50% undivided, non-operating interest in the Burns Point Plant, a natural gas processing plant. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, North Dakota, Tennessee and Texas, provide critical infrastructure that links producers of natural gas, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. We currently operate approximately 3,000 miles of pipelines that gather and transport over 1 Bcf/d of natural gas and operate approximately 1.7 million barrels of storage capacity across four marine terminal sites.

Significant financial highlights during the year ended December 31, 2014, include the following:

- Gross margin increased to $102.8 million for the year ended December 31, 2014, or an increase of 37.4%, compared to the same period in 2013;
- Adjusted EBITDA increased to $45.6 million for the year ended December 31, 2014 , or an increase of 42.8%, compared to the same period in 2013;
- We distributed $22.7 million to holders of our common units, or $1.85 per unit, during the year ended December 31, 2014, as compared to $1.75 per unit for the same period in 2013;
- On August 11, 2014, we acquired a 66.7% non-operated interest in MPOG which recognized cash received in excess of earnings on unconsolidated affiliates of $1.6 million for the year ended December 31, 2014;
- On August 20, 2014, we completed a private offering ("2014 PIPE offering") with certain institutional investors for the sale of 4,622,352 common units and received $119.3 million in cash proceeds; and
- On September 5, 2014, we entered into an amended and restated credit agreement, which provides for a maximum borrowing equal to $500.0 million, with the ability to further increase the borrowing capacity subject to lender approval.

Significant operational highlights during the year ended December 31, 2014, include the following:

- We continued to diversify our asset base with the acquisition of Costar Midstream, an onshore gathering and processing company, with its primary gathering, processing, fractionation, and off-spec condensate treating and stabilization assets in East Texas and the Permian basin, with a significant crude oil gathering system project underway in the Bakken oil play;
- We also acquired approximately 120 miles of high- and low-pressure pipelines ranging from 4 to 8 inches in diameter with over 9,000 horsepower of leased compression, and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas, which we expanded to 203 miles of pipeline and 32,000 horsepowers of compression to service dedicated acreage;
- Throughput attributable to the Partnership totaled 1,053.7 MMcf/d for the year ended December 31, 2014, representing a 14.3% increase compared to the same period in 2013;
- Average gross condensate production totaled 75.2 Mgal/d for the year ended December 31, 2014, representing a 62.8% increase compared to the same period in 2013;
- Average gross NGL production totaled 64.2 Mgal/d for the year ended December 31, 2014, representing a 23.5% increase compared to the same period in 2013; and
- Contracted capacity for our Terminals segment totaled approximately 1,388,070 barrels at December 31, 2014, representing a 7.3% increase compared to the same period in 2013.

Our Operations

We manage our business and analyze and report our results of operations through three business segments:

- Gathering and Processing. Our Gathering and Processing segment provides "wellhead-to-market" services to producers of natural gas and oil, which include transporting raw natural gas from various receipt points through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs from the natural gas, fractionating NGLs, and selling or delivering pipeline-quality natural gas as well as NGLs to various markets and pipeline systems.

- Transmission. Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, which include LDCs, utilities and industrial, commercial and power generation customers.
- Terminals. Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including crude oil, bunker fuel, distillates, chemicals and agricultural products.

Gathering and Processing Segment

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Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas we gather and process, the commercial terms in our current contract portfolio and natural gas, NGL and condensate prices. We gather and process gas primarily pursuant to the following arrangements:

- Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed cash fee for gathering and processing and transporting natural gas.
- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas and off-spec condensate from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas or off-spec condensate at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas or off-spec condensate, we are able to lock in a fixed margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.
- Percent-of-Proceeds Arrangements ("POP"). Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas, NGLs and condensate at market prices. Where we provide processing services at the processing plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, such as under our Toca contract, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas, such as for our interest in the Burns Point Plant. Our POP arrangements also often contain a fee-based component.
- Interest in the Burns Point Plant. We account for our 50% interest in the Burns Point Plant using the proportionate consolidation method. Under this method, we include in our consolidated statement of operations, our value of plant revenues taken in-kind and plant expenses reimbursed to the operator.
- Interest in the Chatom System. We account for our 92.2% undivided interest in the Chatom system pursuant to Accounting Standards Clarification ("ASC") No. 810-10-65-1, Noncontrolling Interests. Under this method, revenues, expenses, gains, losses, net income or loss, and other comprehensive income are reported in the consolidated financial statements at the consolidated amounts, which include the amounts attributable to the partners' and the noncontrolling interests. The consolidated income statement shall separately present net income attributable to the partners' and the noncontrolling interests.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in volumes and, thus, a decrease in our fee-based and fixed-margin gross margin. These arrangements provide stable cash flows but minimal, if any, upside in higher commodity-price environments. Under our typical POP arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our POP arrangements also often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure to commodity price risk through our hedging program. Please read " —Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk."

Transmission Segment

Results of operations from our Transmission segment are determined by capacity reservation fees from firm transportation contracts and the volumes of natural gas transported on the interstate and intrastate pipelines we own pursuant to interruptible transportation or fixed-margin contracts. Our transportation arrangements are further described below:

- Firm Transportation Arrangements. Our obligation to provide firm transportation service means that we are obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the shipper utilizes the capacity. In most cases, the shipper also pays a variable-use charge with respect to quantities actually transported by us.
- Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper to the extent that we have available capacity. For this service the shipper pays no reservation charge but pays a variable-use charge for quantities actually shipped.
- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an

identical volume of natural gas at delivery points on our systems at the same undiscounted index price. We view fixed-margin arrangements to be economically equivalent to our interruptible transportation arrangements.

Terminals Segment

In our Terminals segment, we generally receive fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services provided to our customers, such as excess throughput, truck weighing, etc. The terms of our firm storage contracts are multiple years, with renewal options.

Contract Mix

Set forth below is a table summarizing our average contract mix relative to segment gross margin for the years ended December 31, 2014 and 2013 (in millions):

| | For the Year Ended December 31, 2014 | | | For the Year Ended December 31, 2013 | | |
|---|---|---|---|---|---|---|
| | Segment Gross Margin | Percent of Segment Gross Margin | | Segment Gross Margin | Percent of Segment Gross Margin | |
| Gathering and Processing | | | | | | |
| Fee-based | $21.4 | 42.1 | % | $8.9 | 24.0 | % |
| Fixed margin | 3.1 | 6.2 | % | 2.0 | 5.4 | % |
| Percent-of-proceeds | 26.3 | 51.7 | % | 26.1 | 70.6 | % |
| Total | 50.8 | 100.0 | % | $37.0 | 100.0 | % |
| Transmission | | | | | | |
| Firm transportation | $11.1 | 25.9 | % | $10.6 | 32.7 | % |
| Interruptible transportation | 31.7 | 74.1 | % | 21.7 | 67.0 | % |
| Fixed margin | — | — | % | 0.1 | 0.3 | % |
| Total | 42.8 | 100.0 | % | $32.4 | 100.0 | % |
| Terminals (a) | | | | | | |
| Firm storage | $9.2 | 100.0 | % | $5.4 | 100.0 | % |
| Total | 9.2 | 100.0 | % | $5.4 | 100.0 | % |

(a) Terminals segment amounts are for the period from April 15, 2013 to December 31, 2013 for the year ended December 31, 2013.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics include throughput volumes, gross margin and direct operating expenses on a segment basis, and adjusted EBITDA on a company-wide basis.

Throughput Volumes

In our Gathering and Processing segment, we must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our systems. Our ability to maintain or increase existing volumes of natural gas and obtain new supplies is impacted by i) the level of work-overs or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to or near our gathering systems, ii) our ability to compete for volumes from successful new wells in the areas in which we operate, iii) our ability to obtain natural gas that has been released from other commitments and iv) the volume of natural gas that we purchase from connected systems. We actively monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

In our Transmission segment, the majority of our segment gross margin is generated by firm and interruptible capacity reservation fees from throughput volumes on our interstate and intrastate pipelines. Substantially all Transmission segment gross margin is generated under contracts with shippers, including producers, industrial companies, LDCs and marketers, for firm and interruptible natural gas transportation on our pipelines. We routinely monitor natural gas market activities in the areas served by our transmission systems to pursue new shipper opportunities.

In our Terminals segment, throughput fees are charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services; such as excess throughput, truck weighing and related services.

Gross Margin and Segment Gross Margin

Gross margin and segment gross margin are metrics that we use to evaluate our performance. We define segment gross margin in our Gathering and Processing segment as revenue generated from gathering and processing operations less the cost of natural gas, NGLs and condensate purchased and revenue from construction, operating and maintenance agreements ("COMA"). Revenue includes revenue generated from fixed fees associated with the gathering and treating of natural gas and from the sale of natural gas, NGLs and condensate resulting from gathering and processing activities under fixed-margin and percent-of-proceeds arrangements. The cost of natural gas, NGLs and condensate includes volumes of natural gas, NGLs and condensate remitted back to producers pursuant to percent-of-proceeds arrangements and the cost of natural gas purchased for our own account, including pursuant to fixed-margin arrangements.

We define segment gross margin in our Transmission segment as revenue generated from firm and interruptible transportation agreements and fixed-margin arrangements, plus other related fees, less the cost of natural gas purchased in connection with fixed-margin arrangements. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

We define segment gross margin in our Terminals segment as revenue generated from fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers less direct operating expense which includes direct labor, general materials and supplies and direct overhead.

We define gross margin as the sum of our segment gross margin for our Gathering and Processing, Transmission and Terminals segments. The GAAP measure most comparable to gross margin is net income (loss) attributable to the Partnership.

Effective October 1, 2012, we changed our segment gross margin measure to exclude COMA income. For the year ended December 31, 2012, $0.7 million and $2.7 million in COMA income was excluded from our Gathering and Processing segment gross margin and our Transmission segment gross margin, respectively.

Direct Operating Expenses

Our management seeks to maximize the profitability of our operations in part by minimizing direct operating expenses without sacrificing safety or the environment. Direct labor costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities, lost and unaccounted for gas, and contract services comprise the most significant portion of our operating expenses. These expenses are relatively stable and largely independent of throughput volumes through our systems but may fluctuate depending on the activities performed during a specific period.

Adjusted EBITDA

Adjusted EBITDA is a measure used by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to support our indebtedness and make cash distributions to our unit holders and General Partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

We define adjusted EBITDA as net income, plus interest expense, income tax expense, depreciation expense, certain non-cash charges such as non-cash equity compensation, unrealized losses on commodity derivative contracts, cash distributions in excess of earnings from unconsolidated affiliates and selected charges that are unusual or nonrecurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts, amortization of commodity put purchase costs, and selected gains that are unusual or nonrecurring. The GAAP measure most directly comparable to adjusted EBITDA is net income (loss) attributable to the Partnership.

Note About Non-GAAP Financial Measures

Gross margin and adjusted EBITDA are non-GAAP financial measures. Each has important limitations as an analytical tool because it excludes some, but not all, items that affect the most directly comparable GAAP financial measures. Management compensates for the limitations of these non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management's decision-making process.

You should not consider any of gross margin or adjusted EBITDA in isolation or as a substitute for or more meaningful than analysis of our results as reported under GAAP. Gross margin and adjusted EBITDA may be defined differently by other companies in our industry. Our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

The following tables reconcile the non-GAAP financial measures of gross margin and adjusted EBITDA used by management to Net (loss) income attributable to the Partnership, their most directly comparable GAAP measure, for each of the three years ended December 31, 2014, 2013 and 2012 (in thousands):

| | For the Year ending December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Reconciliation of Gross Margin to Net income (loss) attributable to the Partnership | | | |
| Gathering and processing segment gross margin | $50,817 | $36,985 | $36,118 |
| Transmission segment gross margin | 42,828 | 32,408 | 13,313 |
| Terminals segment gross margin (a) | 9,162 | 5,428 | — |
| Total gross margin | 102,807 | 74,821 | 49,431 |
| Plus: | | | |
| Gain (loss) on commodity derivatives, net | 1,091 | 28 | 3,400 |
| Less: | | | |
| Direct operating expenses (b) | 39,360 | 27,833 | 17,183 |
| Selling, general and administrative expenses | 23,103 | 19,079 | 14,309 |
| Equity compensation expense | 1,536 | 2,094 | 1,783 |
| Depreciation, amortization and accretion expense | 28,832 | 30,002 | 21,287 |
| (Gain) loss on involuntary conversion of property, plant and equipment | — | (343) | 1,021 |
| (Gain) loss on sale of assets | 122 | — | (123) |
| Loss on impairment of property, plant and equipment | 99,892 | 18,155 | — |
| Interest expense | 7,577 | 9,291 | 4,570 |
| Other expense | 670 | — | — |
| Earnings in unconsolidated affiliates | (348) | — | — |
| Other, net (c) | (208) | 226 | (965) |
| Income tax expense (benefit) | 557 | (495) | — |
| Income (loss) from operations of disposal groups, net of tax | 611 | 2,413 | 18 |
| Net income (loss) attributable to noncontrolling interest | 214 | 633 | 256 |
| Net income (loss) attributable to the Partnership | $(98,020) | $(34,039) | $(6,508) |

(a)

Terminals segment amounts are for the period from April 15, 2013 to December 31, 2013 for the year ended December 31, 2013.

(b) Direct operating expenses includes Gathering and Processing segment direct operating expenses of $23.8 million and Transmission segment direct operating expenses of $15.6 million for the year ended December 31, 2014. Direct operating expenses related to our Terminals segment of $6.3 million are included within the calculation of Terminals segment gross margin.

(c) Other, net includes realized gain on commodity derivatives of $0.7 million, $1.1 million and $2.4 million and COMA income of $0.9 million, $0.8 million and $3.4 million for the year ended December 31, 2014, 2013 and 2012, respectively.

| | For the Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Reconciliation of Adjusted EBITDA to Net income (loss) attributable to the Partnership | | | |
| Net income (loss) attributable to the Partnership | $(98,020) | $(34,039) | $(6,508) |
| Add: | | | |
| Depreciation, amortization and accretion expense | 28,832 | 30,002 | 21,287 |
| Interest expense | 6,433 | 7,850 | 4,570 |
| Debt issuance costs | 3,841 | 2,113 | 1,564 |
| Unrealized (gain) loss on derivatives, net | (595) | 1,495 | (992) |
| Non-cash equity compensation expense | 1,626 | 2,094 | 1,783 |
| Transaction expenses | 1,794 | 3,987 | — |
| Income tax expense (benefit) | 224 | (847) | — |
| Impairment on property, plant and equipment | 99,892 | 18,155 | — |
| Loss on impairment of noncurrent assets held for sale | 673 | 2,400 | — |
| Proceeds from equity method investment, return of capital | 1,632 | — | — |
| Deduct: | | | |
| COMA income | 943 | 843 | 3,373 |
| Straight-line amortization of put costs (a) | — | 119 | 291 |
| OPEB plan net periodic benefit | 45 | 73 | 88 |
| Gain (loss) on involuntary conversion of property, plant and equipment | — | 343 | (1,021) |
| Gain (loss) on sale of assets, net | (207) | (75) | 123 |
| Adjusted EBITDA | $45,551 | $31,907 | $18,850 |

(a) Amounts noted represent the straight-line amortization of the cost of commodity put contracts over the life of the contract.

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- On July 1, 2012, we acquired an 87.4% undivided interest in the Chatom system from affiliates of Quantum Resources Management, LLC. The acquisition fair value of consideration of $51.4 million includes a credit associated with the cash flow the Chatom Assets generated between January 1, 2012, and the effective date of July 1, 2012;
- On April 15, 2013, our General Partner contributed the High Point System;
- On December 17, 2013, we completed the acquisition of the Terminals segment. The acquisition of Blackwater represents a transaction between entities under common control and a change in reporting entity. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period or date of common control. Therefore, net assets received were recorded at their historical book value of $22.7 million as of the date common control was established, which is April 15, 2013;
- 

During the fourth quarter of 2013, we acquired an additional 4.8% undivided interest in the Chatom system, increasing our ownership of the Chatom system to a total of 92.2%.

- On January 31, 2014, we acquired our Lavaca System, which is an onshore gas gathering system for approximately $104.4 million.
- On August 11, 2014, we acquired a 66.7% non-operated interest in MPOG, which is an offshore oil gathering system, for a net purchase price of $12.0 million. The acquisition was financed through the Partnership's credit facility. The

interest is accounted for as an equity method investment under ASC 323, Investments-Equity Method and Joint Ventures.

- On October 14, 2014, we acquired Costar Midstream from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC for approximately $471.5 million.

General Trends and Outlook

During 2015, our business objectives will continue to focus on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. We believe the key elements to stable distributable cash flows are the diversity of our asset portfolio and our fee-based business which represents a significant portion of our estimated margins, the objective of which is to protect against downside risk in our distributable cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $5.5 million and $6.5 million, and approved expenditures for expansion capital of between $125.0 million and $135.0 million, for the year ending December 31, 2015. Forecasted growth capital expenditures include construction of midstream infrastructure for the Lavaca and Bakken systems, completion of the Longview rail facility, development of the Natchez Line on the Midla system, the continued build-out of the Harvey Terminal, and other organic growth projects.

We expect to continue to pursue a multi-faceted growth strategy, which includes maximizing drop down opportunities provided by our relationship with ArcLight Capital Partners, capitalizing on organic expansion and opportunities pursuing strategic third party acquisitions in order to grow our distributable cash flows.

We expect our business to continue to be affected by the key trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Gathering and Processing Segment. Except for our fee-based contracts, which may be impacted by throughput volumes, the profitability of our gathering and processing segment gross margin is dependent upon commodity prices, natural gas supply, and demand for natural gas, NGLs and condensate. Commodity prices, which are impacted by the balance between supply and demand, have historically been volatile and saw a significant decline in the latter part of 2014 and early 2015. Throughput volumes could decline, particularly in areas with lower NGL content, should natural gas prices and drilling levels continue to experience weakness.

Transmission Segment.  Profitability of our transmission segment gross margin is dependent upon the demand to transport natural gas pursuant to our firm and interruptible transportation contracts. Throughput volumes could decline should natural gas prices and drilling levels continue to experience weakness as a result of volatile commodity prices.

Terminals Segment.  Profitability of our terminals segment gross margin is dependent upon the demand from our customers to store their products, which is generally not tied to the oil and gas commodity markets. Currently, we have not experienced deterioration of terminal gross margin in connection with the volatility of the natural gas, NGL or condensate markets. Further, the terms of our firm storage contracts are multiple years, with renewal options.

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $107.26 per barrel to a low of $44.45 per barrel from January 1, 2014 through March 5, 2015. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $6.15 per MMBtu to a low of $2.58 per MMBtu from January 1, 2014 through March 5, 2015. We are unable to predict future potential movements in the market price for natural gas, oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices continue to trend lower as they did in the latter part of 2014 and early 2015, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants in our revolving credit facility. Our long-term view is that as economic conditions continue to improve, commodity prices should remain at levels that would support continued natural gas and oil production in the United States. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

Capital Markets. Volatility in the capital markets may impact our operations in multiple ways, including limiting our producers' ability to finance their drilling and workover programs and limiting our ability to fund our operations through drop downs, organic growth projects and acquisitions.

Impact of Inflation on Direct Operating Expenses. Inflation has been relatively low in the United States in recent years. However, the inflation rates impacting our operations fluctuate throughout the broad economic and energy business cycles. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high-energy commodity prices.

Recent Events

Distribution

On January 22, 2015, we announced that the board of directors of our General Partner declared a quarterly cash distribution of $0.4725 per unit for the fourth quarter ended December 31, 2014, or $1.89 per unit on an annualized basis. The cash distribution was paid on February 13, 2015, to unitholders of record as of the close of business on February 6, 2015, together with our General Partner.

Results of Operations — Combined Overview

For the year ended December 31, 2014, gross margin increased by $28.0 million, or 37.4%, to $102.8 million compared to the same period in 2013. The increase in gross margin was largely a result of: i) an increase of gross margin in our Transmission segment of $10.4 million primarily as a result of an increase in throughput of 134.2 MMcf/d from our High Point System, period over period; ii) an increase in gross margin in our Gathering and Processing segment of $13.8 million due to incremental gross margin associated with the acquisitions of our Lavaca System of $16.5 million and the gathering and processing assets of Costar Midstream of $8.0 million, offset by gross margin declines from other gathering and processing assets; and iii) an increase in gross margin in our Terminals segment of $3.7 million due to incremental storage capacity and associated customers.

For the year ended December 31, 2014, Adjusted EBITDA increased $13.6 million, or 42.8%, compared to the same period in 2013. The increase is primarily related to a lower loss attributable to the Partnership of $17.8 million (excluding non-cash impairment charges) and cash received in excess of earning on unconsolidated affiliates of $1.6 million; offset by i) lower depreciation, amortization and accretion expense of $1.2 million; ii) lower interest expense of $1.4 million; and iii) lower unrealized losses on commodity derivatives of $2.1 million.

We distributed $22.7 million to holders of our common units, or $1.85 per unit, during the year ended December 31, 2014, including the distribution with respect to the three months ended December 31, 2013.

The following table and discussion presents certain of our historical consolidated financial data for the periods indicated.

The results of operations by segment are discussed in further detail following this combined overview (in thousands):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Statement of Operations Data: | | | |
| Revenue | $307,309 | $294,051 | $204,868 |
| Gain (loss) on commodity derivatives | 1,091 | 28 | 3,400 |
| Total revenue | 308,400 | 294,079 | 208,268 |
| Operating expenses: | | | |
| Purchases of natural gas, NGLs and condensate | 197,952 | 215,053 | 154,472 |
| Direct operating expenses | 45,702 | 32,236 | 17,183 |
| Selling, general and administrative expenses | 23,103 | 19,079 | 14,309 |
| Equity compensation expense | 1,536 | 2,094 | 1,783 |
| Depreciation, amortization and accretion expense | 28,832 | 30,002 | 21,287 |
| Total operating expenses | 297,125 | 298,464 | 209,034 |
| Gain (loss) on involuntary conversion of property, plant and equipment | — | 343 | (1,021) |
| Gain (loss) on sale of assets, net | (122) | — | 123 |
| Loss on impairment of property, plant and equipment | (99,892) | (18,155) | — |
| Operating income (loss) | (88,739) | (22,197) | (1,664) |
| Other income (expenses): | | | |
| Interest expense | (7,577) | (9,291) | (4,570) |
| Other expense | (670) | — | — |
| Earnings in unconsolidated affiliates | 348 | — | — |
| Net income (loss) before income tax (expense) benefit | (96,638) | (31,488) | (6,234) |
| Income tax (expense) benefit | (557) | 495 | — |
| Net income (loss) from continuing operations | (97,195) | (30,993) | (6,234) |
| Discontinued operations: | | | |
| Income (loss) from operations of disposal groups, net of tax | (611) | (2,413) | (18) |
| Net income (loss) | (97,806) | (33,406) | (6,252) |
| Net income (loss) attributable to noncontrolling interests | 214 | 633 | 256 |
| Net income (loss) attributable to the Partnership | $(98,020) | $(34,039) | $(6,508) |
| | | | |
| Other Financial Data: | | | |
| Gross margin (a) | $102,807 | $74,821 | $49,431 |
| Adjusted EBITDA (a) | $45,551 | $31,907 | $18,850 |

(a) For definitions of gross margin and adjusted EBITDA and reconciliations to their most directly comparable financial measure calculated and presented in accordance with GAAP, and a discussion of how we use gross margin and adjusted EBITDA to evaluate our operating performance, please read "— How We Evaluate Our Operations."

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

Revenue. Our revenue for the year ended December 31, 2014 was $307.3 million compared to $294.1 million for the year ended December 31, 2013. This increase of $13.2 million was primarily due to: i) natural gas revenues increased $9.3 million as a result of higher realized natural gas prices of $4.92/Mcf, an increase of $0.89/Mcf, or 22.1%, period over period; ii) NGL revenues increased $0.3 million as a result of higher gross NGL production volumes of 12.2 Mgal/d from our Gathering and Processing segment and higher realized NGL prices of $0.91/gal, an increase of $0.01/gal period over period; iii) condensate revenues decreased $9.0 million as a result of lower realized condensate prices of $1.62/gal, a decrease of $0.67/gal period over period, partially offset by higher condensate production of 29.0 Mgal/d; iv) transmission revenues from the transportation of natural gas increased $9.1 million, or 11.6%, primarily due to an increase in throughput of 134.2 MMcf/d as a result of the benefit of twelve months of revenue from the High Point System in 2014, compared to less than nine months in 2013; and v) Terminals segment revenue increased $5.7 million primarily due to higher contracted storage capacity and auxiliary services as well as having the benefit of twelve months of revenue from Terminals in 2014, compared to less than nine months in 2013.

Gain on commodity derivatives, net. Gain on commodity derivatives, net presents our commodity derivatives which were comprised of financial swaps, collars and option contracts used to mitigate commodity price risk that have settled in 2014 or will be settled in 2015. These increased $1.1 million period over period due to holding net short positions in a declining commodity price market. For a discussion of our commodity derivative positions, please read "Item 7a. Quantitative and Qualitative Disclosures about Market Risk."

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2014, were $198.0 million compared to $215.1 million in the year ended December 31, 2013. This decrease of $17.1 million was primarily due to lower natural gas purchase volumes associated with our fixed-margin contracts and realized condensate prices, offset by higher purchase costs associated with NGL and condensate production and higher realized natural gas prices related to POP contracts associated with owned processing plants.

Gross Margin. Gross margin for the year ended December 31, 2014, was $102.8 million compared to $74.8 million for the year ended December 31, 2013. This increase of $28.0 million was primarily due to: i) an increase in gross margin in our Transmission segment of $10.4 million as a result of increased throughput of 134.2 MMcf/d primarily as a result of twelve months of activity on our High Point Systems in 2014 compared to less than nine months of activity in 2013; ii) an increase in our Terminals segment of $3.7 million due to incremental storage capacity and associated customers as well as twelve months of activity in 2014 compared to less than nine months of activity in 2013; iii) an increase in gross margin in our Gathering and Processing segment of $13.8 million due to $16.5 million attributable to the acquired Lavaca System and incremental gross margin of $8.0 million attributable to the acquired assets of Costar Midstream, offset by declines in gross margin at our other gathering and processing assets together with lower realized condensate prices of $0.67, or 29.3% period over period.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014, were $45.7 million compared to $32.2 million in the year ended December 31, 2013. This increase of $13.5 million was primarily due to: i) $3.4 million of incremental operating expenses associated with the acquisition of Costar Midstream; ii) $2.0 million of additional material and supplies associated with our Terminal segment; iii) $3.3 million of incremental costs associated with compression rentals; iv) $1.0 million of costs associated with additional pipeline inspections; v) higher salaries, wages and related costs of $1.2 million associated with new personnel additions incurred to manage and integrate our acquisitions and support our continued growth; and vi) $0.8 million associated with integrity management programs.

Selling, General and Administrative Expenses ("SG&A"). SG&A expenses for the year ended December 31, 2014, were $23.1 million compared to $19.1 million for the year ended December 31, 2013. This increase of $4.0 million was primarily due to: i) higher salaries, wages and related costs of $3.4 million associated with new personnel additions incurred to manage and integrate our acquisitions and support our continued growth; ii) an increase in legal fees of $0.9 million associated with certain transactions; and iii) $0.5 million of incremental SG&A associated with the acquisition of Costar Midstream.

Equity Compensation Expense. Compensation expense related to our LTIP for the year ended December 31, 2014, was $1.5 million compared to $2.1 million for the year ended December 31, 2013. This decrease of $0.6 million was primarily due to a one-time grant award made in 2013 associated with the acquisition of the High Point System that did not occur in 2014.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the year ended December 31, 2014, was $28.8 million compared to $30.0 million for the year ended December 31, 2013. This decrease of $1.2 million was primarily due to i) $6.8 million of incremental depreciation of assets associated with acquisitions; and ii) $1.4 million of incremental amortization of intangible assets; offset by $9.2 million of a reduction in depreciation of certain assets becoming fully depreciated in the current period.

Loss on Impairment of Property, Plant and Equipment. During the fourth quarter of 2014, management noted the declining commodity markets and related impact on producers and shippers to whom we provide gathering and processing services. The decline in the market price of crude oil has led to a corresponding decrease in oil and natural gas production and is impacting the volume of natural and NGLs we gather and process on certain assets. As a result, asset impairment charges of $99.9 million related to certain gathering and processing assets were recorded during the fourth quarter of 2014.

Interest Expense. Interest expense for the year ended December 31, 2014, was $7.6 million compared to $9.3 million for the year ended December 31, 2013. This decrease of $1.7 million was primarily due to i) a lower outstanding debt balance and ii) a slight decrease to our weighted average interest rate of 0.73% as a result of lower leverage during the year ended December 31, 2014.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates of $0.3 million represents our 66.7% share of earnings in the MPOG System for the year ended December 31, 2014 which was acquired in August 2014.

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

Revenue. Our revenue for the year ended December 31, 2013 was $294.1 million compared to $204.9 million for the year ended December 31, 2012. This increase of $89.2 million was primarily due to the following: i) natural gas revenues increased $36.6 million as a result of higher realized natural gas prices of $4.03/Mcf, an increase of $1.05/Mcf, or 35.2%, period over period, and increased natural gas sales volumes of 6.0% period over period; ii) NGL revenues increased $3.2 million as a result of higher NGL volumes associated with our elective processing agreement and by higher gross NGL production volumes of 2.1 Mgal/d due to improved volumes from our Gathering and Processing segment offset by lower realized NGL prices of $0.90/gal, a decrease of $0.18/gal period over period; iii) condensate revenues increased $22.4 million as a result of higher condensate production of 23.6 Mgal/d while realized condensate prices remained consistent period over period; iv) transmission revenues from the transportation of natural gas increased $26.5 million primarily as a result of incremental revenue of $30.4 million associated with our High Point System; and v) storage and other revenues of $9.8 million from the inclusion of our Terminals segment.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2013 were $215.1 million compared to $154.5 million in the year ended December 31, 2012. This increase of $60.6 million was primarily due to higher purchase costs associated with natural gas due to higher realized natural gas prices, higher natural gas purchase volumes and higher condensate and NGL production related to POP contracts associated with owned processing plants in our Gathering and Processing segment, partially offset by lower realized NGL prices associated with our POP contracts.

Gross Margin. Gross margin for the year ended December 31, 2013 was $74.8 million compared to $49.4 million for the year ended December 31, 2012. This increase of $25.4 million was primarily due to: i) higher gross margin in our Transmission segment of $19.1 million as a result of incremental gross margin associated with our High Point System of $19.7 million; ii) higher gross margin in our Gathering and Processing segment of $0.9 million due to improved condensate production of 23.6 MMcf/d, or 104.4%, partially offset by lower margins associated with our POP and elective processing agreements in the segment; and iii) contributed gross margin of $5.4 million associated with our Terminals segment.

Direct Operating Expenses. Direct operating expenses in the year ended December 31, 2013 were $32.2 million compared to $17.2 million in the year ended December 31, 2012. This increase of $15.0 million was primarily due to: i) $2.5 million of additional salaries, wages and benefits associated with the contributed High Point System; ii) $2.4 million of costs associated with our property and casualty insurance; iii) $1.7 million associated with additional aerial inspections of our Transmission segment; and iv) $4.4 million associated with our Terminals segment.

Selling, General and Administrative Expenses. SG&A expenses for the year ended December 31, 2013 were $19.1 million compared to $14.3 million for the year ended December 31, 2012. This increase of $4.8 million was primarily due to: i) higher transaction costs of $3.6 million associated with the equity restructuring agreement with our General Partner and HPIP and acquisitions of the High Point System and Blackwater; and ii) incremental costs of $2.9 million associated with our Terminals segment.

Equity Compensation Expense. Compensation expense related to our LTIP for the year ended December 31, 2013 was $2.1 million compared to $1.8 million for the year ended December 31, 2012. This increase of $0.3 million was primarily due to the acceleration of additional unit based awards granted in 2012.

Depreciation Expense. Depreciation expense in the year ended December 31, 2013 was $30.0 million compared to $21.3 million for the year ended December 31, 2012. This increase of $8.7 million was due to depreciation associated with newly acquired facilities and capital projects placed into service during the period.

Loss on Impairment of Property, Plant and Equipment. During the second quarter of 2013, management determined to change its commercial approach towards certain non-strategic gathering and processing assets. As a result, asset impairment charges of $17.0 million were recorded during the second quarter of 2013. In addition, during the first quarter of 2014, the board of directors of our General Partner gave approval to the management team to pursue the sale of certain gathering and processing assets for an amount less than the carrying value of the assets. As a result, these gathering and processing assets were written down by $3.0 million during the fourth quarter of 2013. There was no impairment charge necessary in the comparative periods presented.

Interest Expense. Interest expense for the year ended December 31, 2013, was $9.3 million compared to $4.6 million for the year ended December 31, 2012. This increase of $4.7 million was primarily due to: i) the increase in borrowings under our credit facility and an increase to our weighted average interest rate of 0.42% as a result of the fourth amendment to our former credit agreement; and ii) incremental interest expense of $1.4 million associated with our Terminals segment.

Results of Operations — Segment Results

The table below contains key segment performance indicators related to our segment results of operations (in thousands except operational data):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Segment Financial and Operating Data: | | | |
| Gathering and Processing segment | | | |
| Financial data: | | | |
| Revenue | $203,616 | $205,179 | $152,339 |
| Gain (loss) on commodity derivatives, net | 1,091 | 28 | 3,400 |
| Total revenue | 204,707 | 205,207 | 155,739 |
| Purchases of natural gas, NGLs and condensate | 152,690 | 168,574 | 117,956 |
| Direct operating expenses | 23,783 | 14,574 | 12,152 |
| Other financial data: | | | |
| Segment gross margin | $50,817 | $36,985 | $36,118 |
| Operating data: | | | |
| Average throughput (MMcf/d) | 274.8 | 277.2 | 291.2 |
| Average plant inlet volume (MMcf/d) (a) (b) | 89.1 | 117.3 | 116.1 |
| Average gross NGL production (Mgal/d) (a) (c) | 64.2 | 52.0 | 49.9 |
| Average gross condensate production (Mgal/d) (a) | 75.2 | 46.2 | 22.6 |
| Average realized prices: | | | |
| Natural gas ($/MMcf) | $4.92 | $4.03 | $2.98 |
| NGLs ($/gal) | $0.91 | $0.90 | $1.08 |
| Condensate ($/gal) | $1.62 | $2.29 | $2.30 |
| Transmission segment | | | |
| Financial data: | | | |
| Revenue | $88,189 | $79,041 | $52,529 |
| Purchases of natural gas, NGLs and condensate | 45,262 | 46,479 | 36,516 |
| Direct operating expenses | 15,577 | 13,259 | 5,031 |
| Other financial data: | | | |
| Segment gross margin | $42,828 | $32,408 | $13,313 |
| Operating data: | | | |
| Average throughput (MMcf/d) | 778.9 | 644.7 | 398.5 |
| Average firm transportation - capacity reservation (MMcf/d) | 577.9 | 640.7 | 703.6 |
| Average interruptible transportation - throughput (MMcf/d) | 468.9 | 389.2 | 86.6 |
| Terminals segment (d) | | | |
| Financial data: | | | |
| Total revenue | $15,504 | $9,831 | $— |
| Direct operating expenses | 6,342 | 4,403 | — |
| Other financial data: | | | |
| Segment gross margin | $9,162 | $5,428 | $— |
| Operating data: | | | |
| Storage utilization | 82.9 % | 96.2 % | — |

(a) Excludes volumes and gross production under our elective processing arrangements.
(b) Includes gross plant inlet volume associated with our interest in the Burns Point processing plant.
(c) Includes net NGL production associated with our interest in the Burns Point processing plant.
(d) Terminals segment amounts are for the period from April 15, 2013 to December 31, 2013.

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013

Gathering and Processing Segment

Revenue. Segment revenue for the year ended December 31, 2014 was $204.7 million compared to $205.2 million for the year ended December 31, 2013. This decrease of $0.5 million was primarily due to the following: i) lower average natural gas throughput volumes amounting to 2.4 MMcf/d, or 0.9%, period over period primarily as a result of reduced volumes associated with fixed-margin and POP contracts at certain legacy gathering and processing systems, offset by higher realized natural gas prices of $0.89, or 22.1%; ii) higher average gross condensate production amounting to 29.0 Mgal/d, or a net increase of 62.8%, primarily as a result of condensate production at our Lavaca and High Point Systems, offset by lower realized condensate prices of $0.67, or 29.3%; and iii) higher average gross NGL production amounting to 12.2 Mgal/d, or a net increase of 23.5%, primarily as a result of NGL production at our Longview and Chapel Hill Systems, partially offset by reduced production at certain legacy gathering and processing systems and lower NGL volume associated with our elective processing arrangements.

Gain on commodity derivatives, net. Gain on commodity derivatives, net presents our commodity derivatives which was comprised of financial swaps, collars and option contracts used to mitigate commodity price risk that have settled in 2014 or will be settled in 2015 increased $1.1 million period over period due to holding net short positions in a declining commodity price market. For a discussion of our commodity derivative positions, please read "Item 7a. Quantitative and Qualitative Disclosures about Market Risk."

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2014 were $152.7 million compared to $168.6 million for the year ended December 31, 2013. This decrease of $15.9 million was primarily due to lower natural gas purchase volumes associated with our fixed-margin contracts and realized condensate prices, offset by higher purchase costs associated with NGL and condensate production and higher realized natural gas prices related to fixed-margin and POP contracts associated with owned processing plants.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2014 was $50.8 million compared to $37.0 million for the year ended December 31, 2013. This increase of $13.8 million was primarily due to the following: i) incremental gross margin of $16.5 million at our Lavaca System; ii) incremental gross margin of $8.0 million at our Longview, Chapel Hill and Yellow Rose Systems; partially offset by iii) lower gross margin of $4.6 million due to lower average gross NGL production associated with our elective processing arrangements on our Gloria and Lafitte Systems; as well as lower plant inlet volumes and corresponding NGL sales associated with certain legacy gathering and processing systems of $5.0 million; and iv) a decrease in realized gains of $0.3 million period over period on our commodity derivatives, which was comprised of financial swaps, collars and option contracts used to mitigate commodity price risk.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014 were $23.8 million compared to $14.6 million for the year ended December 31, 2013. This increase of $9.2 million was primarily due to the incremental operating costs associated with our newly acquired Lavaca System and the gathering and processing assets of Costar Midstream.

Transmission Segment

Revenue. Segment revenue for the year ended December 31, 2014, was $88.2 million compared to $79.0 million for the year ended December 31, 2013. This increase of $9.2 million in revenue was primarily due to the following: i) higher realized natural gas prices on our fixed-margin arrangements of $0.84/Mcf, or 22.1%; offset by lower sales volumes of 1.9 MMcf, or 19.0%, amounting to a decrease of $0.4 million; and ii) total natural gas throughput volumes on our transmission systems of 778.9 MMcf/d for the year ended December 31, 2014 compared to 644.7 MMcf/d for the year ended December 31, 2013 representing a 20.8% increase period over period, primarily due to increased natural gas throughput volumes at our High Point System of 147.9 MMcf/d resulting from twelve months of activity in 2014 compared to less than nine months in 2013, partially offset by lower natural gas throughput volumes of 19.5 MMCf/d primarily related to our Midla and Trigas systems.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2014, were $45.3 million compared to $46.5 million for the year ended December 31, 2013. This decrease of $1.2 million was primarily due to i) higher realized natural gas prices, which resulted in higher natural gas purchase costs associated with our fixed-margin arrangements; and ii) an extinguishment of a reserve associated with lower lost and unaccounted for gas on our High Point System.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2014, was $42.8 million compared to $32.4 million for the year ended December 31, 2013. This increase of $10.4 million was primarily due to increased gross margin associated with our High Point System of $12.0 million resulting from i) twelve months of activity in 2014 compared to less than nine months in 2013; and ii) an extinguishment of a reserve associated with lower lost and unaccounted for gas on our High Point System.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014, were $15.6 million compared to $13.3 million for the year ended December 31, 2013. This increase of $2.3 million is primarily due to increased costs associated with our High Point System having twelve months of activity in 2014 compared to less than nine months in 2013.

Terminals Segment

The acquisition of Blackwater represented a transaction between entities under common control and a change in reporting entity. Therefore we have accounted for Blackwater and our Terminals segment as if the transfer occurred as of April 15, 2013, which is the date common control began.

Revenue. Segment total revenue for the year ended December 31, 2014, was $15.5 million compared to $9.8 million for the year ended December 31, 2013. The increase of $5.7 million was primarily attributable to presenting twelve months of activity in 2014 compared to less than nine months in 2013, and an increase in storage capacity, acquiring new customers and contractual storage rate escalations.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2014, were $6.3 million compared to $4.4 million for the year ended December 31, 2013. The increase of $1.9 million is primarily attributable to additional direct labor hours associated with providing ancillary services, and by presenting twelve months of activity in 2014 compared to less than nine months in 2013.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2014, was $9.2 million compared to $5.4 million for the year ended December 31, 2013 as a result of the increase in storage capacity, acquiring new customers and contractual storage rate escalations.

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

Gathering and Processing Segment

Revenue. Segment revenue for the year ended December 31, 2013, was $205.2 million compared to $155.7 million for the year ended December 31, 2012. This increase of $49.5 million was primarily due to the following: i) higher realized natural gas prices of 35.2% offset by lower realized NGL prices of 16.7% period over period as a result of variable commodity prices; ii) higher average gross condensate production amounting to 23.6 Mgal/d, or an increase of 104.4% period over period as a result of our increased production at our Chatom System; iii) higher NGL volume associated with our elective processing agreement and average gross NGL production amounting to 2.1 Mgal/d, or a net increase of 4.2% period over period, as a result of our improved production of 10.7 Mgal/d on our Chatom System; partially offset by iv) lower average natural gas throughput volumes amounting to 14.0 MMcf/d or 4.8% period over period primarily as a result of lower natural gas throughput volumes of 11.5 MMcf/d on our Quivira system.

Gain on commodity derivatives, net. Gain on commodity derivatives, net presents our commodity derivatives which was comprised of financial swaps, collars and option contracts used to mitigate commodity price risk that have settled in 2013 or will be settled in 2014 decreased $3.4 million period over period due to holding net short positions in a rising commodity price market. For a discussion of our commodity derivative positions, please read "Item 7a. Quantitative and Qualitative Disclosures about Market Risk."

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2013, were $168.6 million compared to $118.0 million for the year ended December 31, 2012. This increase of $50.6 million was primarily due to higher purchase costs associated with natural gas due to higher realized natural gas prices, higher natural gas purchase volumes and higher condensate and NGL production related to POP contracts associated with owned processing plants in our Gathering and Processing segment, partially offset by lower realized NGL prices associated with our POP contracts.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2013, was $37.0 million compared to $36.1 million for the year ended December 31, 2012. This increase of $0.9 million was primarily due to the following: i) incremental gross margin of $6.4 million associated with higher average condensate production of 21.3 Mgal/d as a result of the Chatom system; offset by ii) lower gross margins of $1.9 million associated with our Quivira system which saw a decline in volumes of 11.5 Mmcf/d on one of its offshore pipeline systems during 2013; and iii) a decrease in realized gains of $2.2 million period over period on our commodity derivatives which comprised of financial swaps and option contracts which were used to mitigate commodity price risk that settled in 2013.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2013, were $14.6 million compared to $12.2 million for the year ended December 31, 2012. This increase of $2.4 million was primarily due to: i) chemicals and maintenance costs of $1.1 million; and ii) incremental operating costs associated with our 92.2% undivided interest in the Chatom System acquired July 2012 amounting to $1.5 million.

Transmission Segment

Revenue. Segment revenue for the year ended December 31, 2013, was $79.0 million compared to $52.5 million for the year ended December 31, 2012. This increase of $26.5 million in revenue was primarily due to the following: i) higher realized natural gas prices on our fixed margin contracts of $0.87/Mcf amounting to $11.7 million; and ii) total natural gas throughput volumes on our Transmission systems for the year ended December 31, 2013, was 644.7 MMcf/d compared to 398.5 MMcf/d for the year ended December 31, 2012, representing a 61.8% increase period over period primarily due to the contribution of the High Point System, effective April 15, 2013, amounting to $30.4 million.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2013, were $46.5 million compared to $36.5 million for the year ended December 31, 2012. This increase of $10.0 million was primarily due to: i) higher realized natural gas prices, which resulted in higher natural gas purchase costs associated with our fixed margin agreements on MLGT and Midla amounting to $9.2 million; and ii) incremental natural gas costs associated with imbalances and cash-outs in connection with our High Point System of $12.6 million.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2013, was $32.4 million compared to $13.3 million for the year ended December 31, 2012. This increase of $19.1 million was primarily due to incremental gross margin on our High Point System of $19.7 million offset by lower gross margin on our remaining assets of $0.6 million.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2013, were $13.3 million compared to $5.0 million for the year ended December 31, 2012. This increase of $8.3 million was primarily due to our High Point System amounting $6.6 million.

Terminals Segment

The acquisition of Blackwater represented a transaction between entities under common control and a change in reporting entity. Therefore we have accounted for Blackwater and our Terminals segment as if the transfer occurred as of April 15, 2013.

Revenue. Segment total revenue for the year ended December 31, 2013, was $9.8 million which consisted of fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services provided to our customers.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2013, were $4.4 million, which consisted of direct labor, general materials and supplies and direct overhead.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2013, was $5.4 million, which is defined as segment total revenue less direct operating expense.

Liquidity and Capital Resources

Our business is capital intensive and requires significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities.

The principal sources of our liquidity at December 31, 2014, were sources of liquidity we have accessed historically, including available borrowings under our credit facility, issuance of equity in the capital markets under existing registration statements or through private transactions, and financial support from ArcLight Capital Partners, LLC ("ArcLight”), who controls our General

Partner. In addition, in the future we may seek to raise debt financing in the form of unsecured senior notes through a registration statement. Given our historical success in accessing various sources of liquidity, we believe that cash generated from operating cash flows and the sources of liquidity described above will be sufficient to meet our short-term working capital requirements, medium-term maintenance capital expenditure requirements, and quarterly cash distributions for at least the next twelve months. In the event these sources are not sufficient, we would pursue other sources of cash funding, including, but not limited to, additional forms of debt or equity financing. In addition, we would reduce capital expenditures, direct operating expenses and selling, general and administrative expenses, as necessary, and our Partnership agreement allows us to reduce or eliminate quarterly distributions, if required to maintain ongoing operations. Our ability to enhance our liquidity for the year ended December 31, 2014 was as follows:

- In January 2014, we issued 3,400,000 common units at a price to the public of $26.75 per unit. We received proceeds of $86.9 million, net of offering costs;

- On July 14, 2014, we entered into a common unit purchase agreement with certain institutional investors, which agreement was subsequently amended on August 15, 2014 to provide for the sale of 4,622,352 common units representing limited partner interests in a private placement at a price of $25.8075 per common unit (reflecting an adjustment for our second quarter distribution of $0.4625 per unit), for cash consideration of $119.3 million; and

- On October 14, 2014, we acquired Costar Midstream from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC for approximately $471.5 million which was funded with 6.9 million of common units issued directly to Energy Spectrum and Costar senior management, which are subject to certain lock-up provisions, and $265.4 million of cash from borrowings under our revolving credit facility and proceeds from the August 2014 private placement of common units.

Changes in natural gas, NGL and condensate prices and the terms of our contracts have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 7A. "Quantitative and Qualitative Disclosures about Market Risk."

The counterparties to certain of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis.

Our Credit Facility

On September 5, 2014, we entered into an amended and restated credit agreement (the "Credit Agreement"), which provides for a maximum borrowing equal to $500.0 million, with the ability to further increase the borrowing capacity subject to lender approval. The Credit Agreement contains certain financial covenants, including the requirement that our indebtedness not exceed 4.75 times adjusted consolidated EBITDA (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant is increased to 5.25 times adjusted Consolidated EBITDA). We can elect to have loans under our credit facility bear interest either at a Eurodollar-based rate plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its "prime rate," or (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a maximum commitment fee of 0.50% per annum on the undrawn portion of the revolving loan.

Our obligations under the credit facility are secured by a first mortgage in favor of the lenders in our real property. Advances made under the credit facility are guaranteed on a senior unsecured basis by certain of our subsidiaries ("Guarantors"). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the new credit facility include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, September 5, 2019.

The credit facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the credit facility are i) a total consolidated leverage ratio test (not to exceed 4.75 times in the absence of a permitted acquisition); and ii) a minimum interest coverage ratio test (not less than 2.50).

We are required to comply with certain financial covenants and ratios in our credit facility. As of December 31, 2014 our consolidated total leverage was 4.44 and our interest coverage ratio was 13.44, which was in compliance with the consolidated total leverage ratio and interest coverage ratio tests in accordance with the financial covenants required in our Credit Agreement. As of December 31, 2014, we had approximately $373.0 million of outstanding borrowings under our $500.0 million credit facility.

At December 31, 2014 and 2013, letters of credit outstanding under the credit facility were $1.6 million and $4.8 million, respectively.

Working Capital

Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. Our working capital deficit was $14.2 million at December 31, 2014.

Cash Flows

The following table reflects cash flows for the applicable periods (in thousands):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Net cash provided by (used in): | | | |
| Operating activities | $21,478 | $17,223 | $18,348 |
| Investing activities | (471,870) | (28,214) | (62,427) |
| Financing activities | 450,490 | 10,816 | 43,784 |

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013

Operating Activities. Net cash provided by operating activities was $21.5 million for year ended December 31, 2014, compared to $17.2 million for the year ended December 31, 2013. Net cash provided by operating activities for the year ended December 31, 2014, increased primarily due to i) increased gross margin of $28.0 million; ii) a decrease in interest expense of $1.7 million; partially offset by iii) $13.5 million of additional direct operating expenses associated with incremental operating expense of the gathering and processing systems of Costar Midstream, an increase in compression rentals, costs associated with integrity management programs, and additional aerial pipeline inspections; iv) an increase of $4.0 million associated with higher salaries and wages associated with new personnel additions and legal costs incurred to manage and integrate our acquisitions and support our continued growth, and v) settlement of asset retirement obligations of $1.0 million.

One of the primary sources of variability in our cash flows from operating activities is fluctuation in commodity prices, which we partially mitigate by entering into commodity derivatives. Average throughput volume changes also impact cash flow, but have not been as volatile as commodity prices. Our long-term cash flows from operating activities is dependent on commodity prices, average throughput volumes, costs required for continued operations and cash interest expense.

Investing Activities. Net cash used in investing activities was $471.9 million for the year ended December 31, 2014, compared to $28.2 million for the year ended December 31, 2013. Cash used in investing activities for the year ended December 31, 2014 increased by $443.7 million period over period primarily due to i) incremental payments of $362.3 million used to fund the acquisition of gathering and processing assets; ii) $69.8 million of additional capital expenditures primarily associated with expansion capital programs related to the Lavaca System and new terminal storage facilities at Westwego and Harvey, Louisiana; iii) $12.0 million associated with acquisition of a 66.7% undivided interest in MPOG, partially offset by iv) $5.8 million of proceeds related to the divestiture of non-strategic midstream assets.

Financing Activities. Net cash provided by financing activities was $450.5 million for the year ended December 31, 2014, compared to $10.8 million for the year ended December 31, 2013. Cash provided by financing activities for the year ended December 31, 2014, increased by $439.7 million period over period primarily due to i) incremental proceeds from the issuance of common units to the public of $204.3 million and ii) the issuance of Series B Units of $30.0 million, and iii) an increase of $239.8 million in net borrowings from our credit facility in order to finance, in part, the acquisition of Costar Midstream.

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

Operating Activities. Net cash provided by operating activities was $17.2 million for year ended December 31, 2013, compared to $18.3 million for the year ended December 31, 2012. Net cash provided by operating activities for the year ended December 31, 2013, decreased year over year primarily due to: i) $6.6 million and $2.1 million of additional direct operating expenses associated with the contributed High Point System and Blackwater, respectively, and $2.4 million of additional costs associated with our property and casualty insurance; ii) incremental transaction costs and interest payments of $4.0 million and $4.7 million, respectively; iii) a decrease in proceeds received from the settlement of risk management assets and liabilities of $2.2 million; partially offset by iv) incremental gross margin associated with our High Point System of $19.7 million and our gathering and processing segment of $1.1 million.

One of the primary sources of variability in our cash flows from operating activities is fluctuation in commodity prices, which we partially mitigate by entering into commodity derivatives. Average throughput volume changes also impact cash flow, but have not been as volatile as commodity prices. Our long-term cash flows from operating activities is dependent on commodity prices, average throughput volumes, costs required for continued operations and cash interest expense.

Investing Activities. Net cash used in investing activities was $28.2 million for the year ended December 31, 2013, compared to $62.4 million for the year ended December 31, 2012. Cash used in investing activities for the year ended December 31, 2013, decreased year over year primarily due to: i) $20.5 million used to fund the expansion of certain strategic systems; ii) $7.7 million used to fund capital expansion associated with Blackwater; iii) $2.0 million of funding our restricted cash account; and iv) $6.1 million used to fund maintenance capital primarily associated improvements at our Bazor Ridge and other systems, as compared to $51.4 million used to fund the acquisition of the Chatom System in July 2012.

Financing Activities. Net cash provided by financing activities was $10.8 million for the year ended December 31, 2013, compared to net cash provided by financing activities of $43.8 million for the year ended December 31, 2012. Cash provided by financing activities for the year ended December 31, 2013, decreased year over year primarily due to: i) an increase of $2.5 million in net borrowings from our credit facility as result of borrowings to acquire Blackwater offset by contributions from our General Partner; ii) the issuance of the Series A convertible preferred units amounting to $14.4 million; and iii) increased net borrowings from other bank loans of $7.7 million to fund capital expansion associated with Blackwater; partially offset by iv) distribution payments of $16.1 million; as compared to higher net borrowings of $62.0 million associated with the acquisition of the Chatom System in July 2012 for the year ended December 31, 2012.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities. We categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity; or
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the year ended December 31, 2014, capital expenditures totaled $97.0 million including expansion capital expenditures of $90.3 million, maintenance capital expenditures of $6.2 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $0.5 million. Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our partnership agreement. We anticipate maintenance capital expenditures of between $5.5 million and $6.5 million and expansion capital expenditures between $125.0 million and $135.0 million for the year ending December 31, 2015. Forecasted growth capital expenditures include construction of midstream infrastructure for the Lavaca and Bakken systems, completion of the Longview rail facility, development of the Natchez Line on the Midla system, the continued build-out of the Harvey Terminal, and other organic growth projects.

We intend to make cash distributions to our unitholders and our General Partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, which will include debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our credit facility, the issuance of additional partnership units and long-term debt. If these sources are not sufficient, we will reduce our discretionary spending.

Integrity Management

Certain operating assets require an ongoing integrity management program under regulations of the U.S. Department of Transportation, or DOT. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle. Our total program addresses approximately 93 high consequence areas that require on-going testing pursuant to DOT regulations. Over the course of the seven-year cycle, we expect to incur up to $6.0 million in integrity management testing expenses.

Distributions

On January 22, 2015, we announced that the board of directors of our General Partner declared a quarterly cash distribution of $0.4725 per unit for the fourth quarter ended December 31, 2014, or $1.89 per unit on an annualized basis. The cash distribution was paid on February 13, 2015, to unitholders of record as of the close of business on February 6, 2015, together with our General Partner.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2014, our material off-balance sheet arrangements and transactions included operating lease arrangements and service contracts. There are no other transactions, arrangements, or other relationships associated with our investments in unconsolidated affiliates or related parties that are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources. See "Contractual Obligations" below for more information regarding off-balance sheet arrangements.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2014 (in thousands):

| | Total | Long-term debt | Operating leases and | Asset retirement |
|---|---|---|---|---|

| | | | service contracts | obligation |
|---|---|---|---|---|
| Less Than 1 Year | $6,336 | $2,908 | $3,428 | $— |
| 1 - 3 Years | 10,509 | — | 3,625 | 6,884 |
| 3 - 5 Years | 375,781 | 372,950 | 2,831 | — |
| More Than 5 Years | 30,706 | — | 2,945 | 27,761 |
| Total | $423,332 | $375,858 | $12,829 | $34,645 |

Impact of Seasonality

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Results of operations in our Transmission segment are directly affected by seasonality due to higher demand for natural gas during the winter months, primarily driven by our LDC customers. On our AlaTenn system, we offer some customers seasonally-adjusted firm transportation rates that require customers to reserve capacity at rates that are higher in the period from October to March compared to other times of the year. On our Midla system, we offer customers seasonally-adjusted firm transportation reservation volumes that allow customers to reserve more capacity during the period from October to March compared to other times of the year. The combination of seasonally-adjusted rates and reservation volumes, as well as higher volumes overall, result in higher revenue and segment gross margin in our Transmission segment during the period from October to March compared to other times of the year. We generally do not experience seasonality in our Gathering and Processing and Terminals segment.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by our management to be critical to an understanding of the financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Use of Estimates. The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect our reported financial positions and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, i) estimating unbilled revenue, operating and general and administrative costs, ii) developing fair value assumptions, including estimates of future cash flows and discount rates, iii) analyzing tangible and intangible assets for possible impairment, iv) estimating the useful lives of our assets, v) accounting for income taxes, and vi) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from our estimates.

Property, Plant and Equipment. In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment is depreciated using the straight-line method over the estimated useful lives of the assets. The costs of renewals and betterments which extend the useful life of property, plant and equipment are also capitalized. The costs of repairs, replacements and maintenance projects are expensed as incurred.

Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. As circumstances warrant, depreciation estimates are reviewed 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.

Impairment of Long-Lived Assets. We assess our long-lived assets for impairment on authoritative guidance. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets. We recognize an impairment loss when the carrying amount of the asset or asset group exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations. We recorded impairments of long-lived assets of $99.9 million, $18.2 million and $0.0 million for the years ended December 31, 2014, 2013 and 2012. A hypothetical increase or decrease in fair value by 1.0% would have changed our impairment by less than $1.0 million for the year ended December 31, 2014.

Impairment of Goodwill. We evaluate goodwill for impairment annually in the fourth quarter, and 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 determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.

Environmental Remediation. Current accounting guidelines require us to recognize a liability and expense associated with environmental remediation if: i) government agencies mandate such activities, ii) the existence of a liability is probable and iii) the amount can be reasonably estimated. As of December 31, 2014, we have recorded no liability for remediation expenditures. If governmental regulations change, we could be required to incur remediation costs that may have a material impact on our profitability.

Asset Retirement Obligations. As of December 31, 2014, we have recorded liabilities of $34.6 million for future asset retirement obligations associated with our pipeline and gathering and processing systems. Related accretion expense has been recorded in Depreciation, amortization and accretion expense as discussed in Note 1 in our consolidated financial statements. The recognition of an asset retirement obligation requires that management make numerous estimates, assumptions and judgments regarding such factors as costs of remediation, timing of settlement to changes in the estimate of the costs of remediation. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset or corresponding liability on a prospective basis and an adjustment in our depreciation expense in future periods.

Revenue Recognition. We recognize revenue when all of the following criteria are met: i) persuasive evidence of an exchange arrangement exists, ii) delivery has occurred or services have been rendered, iii) the price is fixed or determinable and iv) collectability is reasonably assured. We record revenue and cost of product sold on the gross basis for those transactions where we act as the principal and take title to natural gas, NGLs or condensates that is purchased for resale. When our customers pay us a fee for providing a service such as gathering, treating or transportation, we record those fees separately in revenue. Under keep-whole contracts, we keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. Revenue from firm storage contracts is recognized ratably, which is typically monthly, over the term of the lease. Revenue from throughput fees and ancillary fees are recognized as services are provided to the customer and when the fees are realizable.

Natural Gas Imbalance Accounting. Quantities of natural gas over-delivered or under-delivered related to operational balancing agreements are recorded monthly as inventory or as a payable using weighted average prices at the time the imbalance was created. Monthly, gas imbalances over-delivered are valued at the lower of cost or market; gas imbalances under-delivered are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas. Under the contracts, imbalance cash-outs are recorded as a sale or purchase of natural gas, as appropriate.

Equity-Based Awards. We account for equity-based awards in accordance with applicable guidance, which establishes standards of accounting for transactions in which an entity exchanges its equity instruments for goods or services. Equity-based compensation expense is recorded based upon the fair value of the award at grant date. Such costs are recognized as expense on a straight-line basis over the corresponding vesting period.

Price Risk Management Activities. We have structured our hedging activities in order to minimize our commodity pricing and interest rate risks and to help maintain compliance with certain financial covenants in our credit agreement. These hedging activities rely upon forecasts of our expected operations and financial structure through June 2015. If our operations or financial structure are significantly different from these forecasts, we could be subject to adverse financial results as a result of these hedging activities. We mitigate this potential exposure by retaining an operational cushion between our forecasted transactions and the level of hedging activity executed.

From the inception of our hedging program in December 2009, we used mark-to-market accounting for our commodity hedges and interest rate caps. We record monthly realized gains and losses on hedge instruments based upon cash settlements information. The settlement amounts vary due to the volatility in the commodity market prices throughout each month. We also record unrealized gains and losses quarterly based upon the future value on mark-to-market hedges through their expiration dates. The expiration dates vary but are currently no later than June 2015 for our commodity hedges. We monitor and review hedging positions regularly.

Recent Accounting Pronouncements

In April 2014, the FASB issued ASU No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This guidance amends the requirements for reporting discontinued operations and requires expanded disclosures for individually significant components of an entity that either have been disposed of or are classified as held for sale, but do not qualify for discontinued operations reporting. Only those disposals of components of an entity that represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. ASU 2014-08 is effective for annual periods, and interim periods within those years, beginning on or after December 15, 2014 and is applied prospectively. Early adoption is permitted, but only for disposals or classifications as held for sale that have not been reported in financial statements previously issued or available for issuance. The update was early adopted by the Partnership as of April 1, 2014 and did not have a material impact on its consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), which amends the existing accounting standards for revenue recognition. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is not permitted. The Partnership is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements-Going Concern (Topic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This guidance provides additional information to guide management's evaluation of whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. The update is effective for annual periods beginning on or after December 15, 2016. The Partnership has evaluated the impact of this standard on its financial statements and determined it will not have a material impact.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate in our Gathering and Processing segment. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Natural gas and NGL prices are impacted by changes in the supply and demand for natural gas and NGLs, as well as market uncertainty. For a discussion of the volatility of natural gas, NGL and crude oil prices, please read "Item 1A. Risk Factors." Adverse effects on our cash flow from reductions in natural gas, NGL and crude oil product prices could adversely affect our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, optimization of our assets, and the use of derivative contracts. Our overall direct exposure to movements in natural gas prices is minimal as a result of natural hedges inherent in our current contract portfolio. Natural gas prices, however, can also affect our profitability indirectly by influencing the level of drilling activity in our areas of operation. We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing.

To minimize the effect of commodity prices and maintain our cash flow and the economics of our development plans, we enter into commodity hedge contracts from time to time. The terms of the contracts depend on various factors, including management's view of future commodity prices, acquisition economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price downturns while allowing us to participate in some commodity price upside. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the board of directors of our General Partner. Currently, the commodity derivatives are in the form of swaps and collars. As of December 31, 2014, the aggregate notional volume of our commodity derivatives was 0.5 million gallons.

We enter into commodity contracts with counterparties. We may be required to post collateral with our counterparties in connection with our derivative positions. As of December 31, 2014, we have not been required to post collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparties that permit us to offset our commodity derivative asset and liability positions.

During 2014, we entered into additional commodity contracts with existing counterparties to hedge our 2014 and 2015 exposure to commodity prices. As of December 31, 2014, we have hedged approximately 4% of our expected exposure to NGL prices for the first six months of 2015.

The table below sets forth certain information regarding the financial instruments used to hedge our commodity price risk as of December 31, 2014 (in thousands):

| Commodity | Instrument | Notional Volumes (a) | Average Price | Period | Fair Value at December 31, 2014 |
|---|---|---|---|---|---|
| NGLs (gals) | Swaps | (480,000) | $1.10 | Jan 2015 - June 2015 | $(286) |

(a) Contracted volumes represented as a net short financial position by instrument.

Interest Rate Risk

During the year ended December 31, 2014, we had exposure to changes in interest rates on our indebtedness associated with our credit facility. During the second quarters of 2013 and 2014, we entered into interest rate swaps to manage the impact of the interest rate risk associated with our credit facility, effectively converting the cash flows related to $100 million of our long-term variable rate debt into fixed rate cash flows.

The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will begin to tighten, resulting in higher interest rates. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $1.7 million for the year ended December 31, 2014.

## Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the reports of our independent registered public accounting firm, begin on F-1 of this Annual Report.

## Item 9. Changes in and Disagreements with Accountants and Financial Disclosure

None.

## Item 9A. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms, and that such information is accumulated and communicated to the management of our General Partner, including our General Partner’s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. Due to the material weakness in internal control over financial reporting described below our Certifying Officers have concluded our disclosure controls and procedures are ineffective as of December 31, 2014.

We did not design and maintain effective internal controls over the completeness and accuracy of spreadsheets. Specifically, our guidelines were not precise enough in describing the level of review to be performed regarding the inputs, assumptions, and formulas used in spreadsheets. This control deficiency resulted in audit adjustments to goodwill, intangible assets, and amortization expense during the year ended December 31, 2014 and immaterial out-of-period adjustments to our consolidated financial statements for each of the interim periods in the year-ended December 31, 2014. Additionally, this control deficiency could result in a misstatement of the account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management determined that this control deficiency constitutes a material weakness.

### Remediation plan for spreadsheet deficiencies

With respect to the identified material weakness, we will develop specific guidance describing the level of reviews to be performed on our key spreadsheets used in the preparation and analysis of accounting and financial information, including validating inputs, assumptions and formulas. We will continue to focus on continuing education for our current accounting and finance staff.

Remediation of third quarter deficiencies

As previously disclosed in our amended Form 10-Q/A filed on December 23, 2014, we identified material weaknesses in our internal control over financial reporting described below that were related to an entity acquired in 2013 and, therefore, excluded from our assessment of internal control over financial reporting as of December 31, 2013.

The material weaknesses were we determined we did not design and maintain effective controls related to certain process-level activities for a newly acquired business that contributed to the following design material weaknesses related to: i) The precision of the review of supporting documentation regarding the existence and occurrence of condensate revenues; and ii) The omission of a control to validate whether the measurement input agreed to supporting documentation regarding the completeness and accuracy of data used in the calculation of pipeline Lost and Unaccounted For.

In response to the material weaknesses relating to the newly acquired business described above, management took the following immediate steps and remediated the material weaknesses as of December 31, 2014.

- Introduced additional controls to improve the accuracy of source information used to record certain transactions.
- Modified certain controls to validate the accuracy of recorded transactions at a higher level of precision.
- Provided additional training of accounting staff to apply appropriate precision and rigor when reviewing journal entries and ensuring that all accounting reconciliations and journal entries are appropriately prepared and reviewed related to i) the precision of the review of supporting documentation regarding the existence and occurrence of condensate revenues; and ii) the validation of whether the measurement input agreed to supporting documentation regarding the completeness and accuracy of data used in the calculation of pipeline Lost and Unaccounted For.

Management tested the newly implemented and modified controls and found them to be effective and have concluded that as of December 31, 2014, these material weaknesses have been remediated.

Inherent limitations of internal controls

Our management, including our Certifying Officers, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) will prevent or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been prevented or detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations with a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Therefore, management monitors the Partnership’s disclosure controls and procedures and make modifications, as necessary, with the intent that the disclosure controls and procedures will be adequately designed and operating effectively to prevent or detect material misstatements to its consolidated financial statements and to deter fraud.

Management's Annual Report on Internal Control over Financial Reporting

Management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). The Partnership’s internal control over financial reporting was designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2014. This assessment was based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on our assessment, management concluded that as of December 31, 2014 the Partnership’s internal control over financial reporting was ineffective due to the material weakness described below.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Partnership's annual or interim financial statements would not be prevented or detected on a timely basis.

We did not design and maintain effective internal controls over the completeness and accuracy of spreadsheets. Specifically, our guidelines were not precise enough in describing the level of review to be performed regarding the inputs, assumptions, and formulas used in spreadsheets. This control deficiency resulted in audit adjustments to goodwill, intangible assets, and amortization expense during the year ended December 31, 2014 and immaterial out-of-period adjustments to our consolidated financial statements for each of the interim periods in the year-ended December 31, 2014. Additionally, this control deficiency could result in a misstatement of the account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management determined that this control deficiency constitutes a material weakness.

Management has excluded Costar Midstream, LLC from its assessment of internal control over financial reporting as of December 31, 2014, because it was acquired by the Partnership in a purchased business combination during 2014. Costar Midstream, LLC is a wholly-owned subsidiary whose total assets and total revenues represent 25% and 6%, respectively of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

PricewaterhouseCoopers LLP, the independent registered public accounting firm, that audited the consolidated financial statements included in this Annual Report on Form 10-K, has audited the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2014, as stated in their report which is included on page F-1 of this Annual Report.

Changes in internal control over financial reporting

Management, including our Certifying Officers, evaluated the changes in our internal control over financial reporting for the quarter ended December 31, 2014. As outlined above, management remediated material weaknesses that existed during 2014, and is in the process of adding or modifying controls to remediate the material weakness that exists at December 31, 2014. As such, the changes related to the remediation of the third quarter deficiencies described above were changes to the Partnership’s internal control over financial reporting during the quarter ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

In addition to the changes to certain internal controls over financial reporting made by management in the fourth quarter of 2014, on May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) issued an updated version of its Internal Control - Integrated Framework (the 2013 Framework). Originally issued in 1992 (the 1992 Framework), the framework helps organizations design, implement and evaluate the effectiveness of internal control concepts and simplify their use and application. The 1992 Framework remains available during the transition period, which extends to December 15, 2014, after which time COSO will consider it as superseded by the 2013 Framework. During the year ended December 31, 2014, management completed the process to determine the Partnership was in compliance with the 2013 Framework.

The certifications of our Certifying Officers pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this Annual Report on Form 10-K as Exhibits 31.1 and 31.2. The certifications of our Certifying Officers pursuant to 18 U.S.C. 1350 are furnished with this Annual Report on Form 10-K as Exhibits 32.1 and 32.2.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We do not have directors or officers, which is commonly the case with publicly traded partnerships. We are managed by the directors and executive officers of our General Partner, American Midstream GP, LLC. Our General Partner is not elected by our unitholders and will not be subject to re-election in the future. HPIP and AIM Midstream Holdings own all of the membership interests in our General Partner. Our General Partner has a board of directors (the "Board"), and our unitholders are not entitled to elect the directors or directly or indirectly participate in our management or operations. Our General Partner owes certain fiduciary duties to our unitholders. Our General Partner is liable, as General Partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our General Partner.

Our partnership agreement provides for the board of directors of our General Partner to designate a Conflicts Committee ("Conflicts Committee"), as delegated by the Board as circumstances warrant, to review conflicts of interest between us and our General Partner or between us and affiliates of our General Partner. If the Board submits a matter to the Conflicts Committee, which will consist solely of independent directors, for their review and approval, the Conflicts Committee will determine if the resolution of a conflict of interest that has been presented to it by the Board is fair and reasonable to us. The members of the Conflicts Committee may not be executive officers or employees of our General Partner or directors, executive officers or employees of its affiliates. In addition, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders. In addition, the Board has an Audit Committee ("Audit Committee"), that complies with the NYSE requirements and a compensation committee ("Compensation Committee"). During 2013, the Board introduced a hedge committee to oversee risk management activities.

Even though most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a listed limited partnership like us to have a majority of independent directors on the Board.

Our General Partner has adopted a Code of Business Conduct and Ethics, or Code of Ethics, that applies to the directors, officers and employees of our General Partner. If our General Partner amends the Code of Ethics or grants a waiver, including an implicit waiver, for the Code of Ethics, we will disclose the information on our website. Our General Partner has also adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance.

All of the senior officers of our General Partner devote a sufficient portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our business; however, they also devote a portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our General Partner, which has separate ongoing business operations.

The non-management members of our General Partner's board of directors meet in executive sessions without management participation at least quarterly. These directors do not constitute a committee of the Board and therefore do not take action at such sessions, although the participating directors may make recommendations for consideration by the full board. Executive sessions shall be chaired by Gerald A. Tywoniuk, the chairman of the Audit Committee according to the charter of the Audit Committee.

Interested parties may communicate directly with the independent directors by submitting a communication in an envelope marked "Confidential" addressed to the "Independent Members of the Board of Directors" in the care of the Secretary of our General Partner at: American Midstream GP, LLC, 1400 16th Street, Suite 310, Denver, Colorado 80202.

We make available free of charge, within the "Investor Relations—Corporate Governance" section of our website at http://www.americanmidstream.com, and in print to any unitholder who so requests, the Code of Ethics and our Corporate Governance Guidelines. Unitholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Secretary, American Midstream GP, LLC, 1400 16th Street, Suite 310, Denver, Colorado 80202. The information contained on, or connected to, our website is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

The independent directors on our Board are Donald R. Kendall Jr., Rose M. Robeson and Gerald A. Tywoniuk. Each of our independent directors serves as a member of the Audit Committee, with Mr. Tywoniuk serving as chairman.
Our General Partner

is generally required to have at least three independent directors serving on its board at all times. The Board has determined that Mr. Tywoniuk is a financial expert as defined by the NYSE and the Exchange Act and therefore eligible to chair the Audit Committee.

Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the Board and are subject to the terms of their employment agreements, if applicable. The following table shows information for the executive officers and directors of our General Partner as of December 31, 2014:

| Name | Age | Position with American Midstream GP, LLC |
|---|---|---|
| Stephen W. Bergstrom | 57 | Executive Chairman of the Board, President and Chief Executive Officer |
| Robert W. Bourne | 59 | Senior Vice President of Business Development |
| Tom L. Brock | 42 | Vice President, Chief Accounting Officer and Corporate Controller |
| Daniel C. Campbell | 44 | Senior Vice President and Chief Financial Officer |
| William B. Mathews | 63 | Secretary, General Counsel and Vice President of Legal Affairs |
| Matthew W. Rowland | 52 | Senior Vice President and Chief Operating Officer |
| Kevin J. Sullivan | 61 | Executive Vice President |
| John F. Erhard | 40 | Director |
| Donald R. Kendall Jr. | 62 | Director |
| Daniel R. Revers | 53 | Director |
| Rose M. Robeson | 54 | Director |
| Joseph W. Sutton | 66 | Director |
| Lucius H. Taylor | 41 | Director |
| Gerald A. Tywoniuk | 53 | Director |

Executive officers

Stephen W. Bergstrom was elected as a member of the Board in April 2013 and was elected President and Chief Executive Officer in May 2013. He was appointed to the Board in connection with his affiliation with ArcLight, which controls our General Partner, and due to his breadth of experience in the energy industry. Mr. Bergstrom has been acting as an exclusive consultant to ArcLight since 2002, assisting ArcLight in connection with its energy investments. Prior to his consultancy with ArcLight, Mr. Bergstrom worked from 1986 to 2002 for Natural Gas Clearinghouse, which became Dynegy, Inc. Mr. Bergstrom acted in various capacities at Dynegy, ultimately acting as its President and Chief Operating Officer. Prior to his time at Dynegy, Mr. Bergstrom acted as a gas supply representative for Northern Natural Gas from 1981 to 1986. Mr. Bergstrom began his career at Transco from 1980-1981. Mr. Bergstrom earned a Bachelor of Science from Iowa State University in 1979. We believe that Mr. Bergstrom's breadth of experience in the energy industry provide him with the necessary skills to be a member of the Board.

Robert W. Bourne was appointed Senior Vice President of Business Development in November 2014. Prior to his appointment with the General Partner, Mr. Bourne was a Partner at Costar Midstream, L.L.C., which was acquired by American Midstream in October 2014. Prior to his service at Costar Midstream, Mr. Bourne was the Chief Executive Officer of Gas Solutions II, Ltd. until it was acquired by Costar Midstream in 2012. Mr. Bourne has a BS in Finance from Louisiana State University.

Tom L. Brock was appointed Vice President, Chief Accounting Officer and Corporate Controller of the General Partner and the Partnership in November 2013. Mr. Brock had previously served as Vice President and Corporate Controller of the General Partner and the Partnership beginning in July 2012. Prior to his appointment with the General Partner and the Partnership, Mr. Brock held the position of Director of Trading and Finance with BG Group in Houston, Texas, where he controlled accounting and other functions for its marketing and trading companies beginning in July 2010. Mr. Brock began his career with KPMG LLP, where he spent 13 years holding various positions serving clients in the energy industry. Mr. Brock holds a Bachelor of Accountancy from New Mexico State University and is a CPA licensed in the State of Texas.

Daniel C. Campbell was appointed Senior Vice President and Chief Financial Officer in April 2012. Prior to his appointment with the General Partner, Mr. Campbell served in various leadership roles with MarkWest Energy Partners, LP, from 2006 through

2012, most recently as Vice President of Finance and Treasurer. Mr. Campbell joined MarkWest from TeleTech Holdings, Inc., where he held various senior finance roles from 1997 to 2006 in finance, treasury, strategic planning, and investor relations, including Chief Financial Officer of TeleTech Latin America. Mr. Campbell began his career at Arthur Andersen LLP. He received B.S. and Masters degrees in Accounting from Brigham Young University. Mr. Campbell is a CPA licensed in Colorado.

William B. Mathews has served as Secretary and Vice President of Legal Affairs of our General Partner since November 2009 and General Counsel of our General Partner since March 2011. Prior to our formation, he served as Vice President, General Counsel and Secretary of Foothills Energy Ventures, LLC from December 2006 to November 2009, as well as a director from August 2009 to November 2009. Prior to Foothills, Mr. Mathews served as Assistant General Counsel for ONEOK Partners, L.P., Northern Border Partners, L.P., and Bear Paw Energy, LLC, from July 2001 to December 2006 and, previous to that, as Vice President and General Counsel of Duke Energy Field Services (now DCP Midstream, LLC) until 2000, having joined a predecessor company in 1985. He received a J.D. from the University of Denver and a B.S. in Civil Engineering from the University of Colorado.

Matthew W. Rowland was appointed Chief Operating Officer in April 2013. Prior to his appointment with the General Partner, Mr. Rowland was a founder and Managing Director at High Point Energy, LLC (a minority interest owner of HPIP), from 2009 to 2013. Prior to High Point, Mr. Rowland served as Vice President of Asset Optimization for CIMA ENERGY, LTD. from 2003 to 2009. Mr. Rowland began his career with Tenneco/El Paso where he held various operational and commercial roles. Mr. Rowland received a B.S. in Mechanical Engineering from Texas A&M University.

Kevin J. Sullivan was appointed Executive Vice President in November 2014. Prior to his appointment with the General Partner, Mr. Sullivan was the Managing Partner of Costar Midstream, L.L.C., which was acquired by American Midstream in October 2014. Prior to his service at Costar Midstream, Mr. Sullivan was the founder and CEO of American Central Gas Co., Tyler Gas Co., GED Gas Resources and American Compression Leasing Co. Mr. Sullivan holds a BA from Stanford University and a MBA from the University of Southern California.

Directors

John F. Erhard was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Erhard, a Partner at ArcLight, joined the firm in 2001 and has 15 years of energy finance and private equity experience. Prior to joining ArcLight, he was an Associate at Blue Chip Venture Company, a venture capital firm focused on the information technology sector. Mr. Erhard began his career at Schroders, where he focused on mergers and acquisitions. Mr. Erhard earned a Bachelor of Arts in Economics from Princeton University and a Juris Doctor from Harvard Law School. Mr. Erhard previously served on the Board of Directors of Patriot Coal. In addition, Mr. Erhard has experience in the MLP sector having served on the board of directors of Buckeye GP Holdings, the publicly traded General Partner of Buckeye Partners (NYSE: BPL). We believe that Mr. Erhard's 14 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Donald R. Kendall, Jr. was elected a member of the Board in July 2013. Mr. Kendall serves as an independent director and as a member of the Audit Committee. Mr. Kendall is currently Managing Director and Chief Executive Officer of Kenmont Capital Partners, LP, an investment management firm based in Houston specializing in alternative investments and private equity. Prior to joining Kenmont, Mr. Kendall was a Portfolio Manager for Carlson Capital, L.P., President of Cogen Technologies Capital Company, L.P., Chairman and Chief Executive Officer of Palmetto Partners, Ltd., and a Managing Director in the project finance and leasing group at Credit Suisse First Boston. He also currently serves as a director and audit committee chairperson of SolarCity and Stream Energy and as a director of Tangent Energy Solutions. In addition, Mr. Kendall serves in various capacities at not-for-profit organizations, including The Jane Goodall Institute, The Houston Zoo Conservation Committee, and Earthwatch International. He also is on the Board of Overseers of the Amos Tuck School of Business Administration at Dartmouth College. Mr. Kendall received a B.A. degree from Hamilton College and an M.B.A. with high honors from The Amos Tuck School of Business Administration. He was a Tuck Scholar and a recipient of the W. M. Bollenbach, Jr. Fellowship. We believe that Mr. Kendall's investment experience and general business knowledge qualifies him to be a member of the Board. With respect to the Audit Committee, he also qualifies as an "audit committee financial expert."

Daniel R. Revers was elected as a member of the board of directors in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Revers is Managing Partner of and a co-founder of ArcLight and has 25 years of energy finance and private equity experience. Mr. Revers manages the Boston office of ArcLight and is responsible for overall investment, asset management, strategic planning, and operations of ArcLight and its funds. Prior to forming ArcLight in 2000, Mr. Revers was a Managing Director in the Corporate Finance Group at John Hancock Financial Services ("John Hancock"), where he was responsible for the origination, execution, and management of a $6 billion portfolio consisting of debt, equity, and mezzanine investments in the energy industry. Prior to joining John Hancock in 1995, Mr. Revers held various financial positions at Wheelabrator Technologies, Inc., where he specialized in the development, acquisition, and financing of domestic and international power and energy projects. Mr. Revers serves in various capacities for a number of not-for-profit organizations, currently serving on the Board of Overseers at the Amos Tuck School of Business Administration, and the Board of Directors of The Citizen Schools. Mr. Revers earned a Bachelor of Arts in Economics from Lafayette College and a Master of Business Administration from the Amos Tuck School of Business Administration at Dartmouth College. We believe that Mr. Revers's 25 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Rose M. Robeson was elected as a member of the Board in June 2014. Ms. Robeson serves as an independent director and as a member of the Audit Committee. Ms. Robeson also has served as a director of SM Energy since July 2014. Ms. Robeson most recently served as Senior Vice President and Chief Financial Officer of DCP Midstream GP, LLC, the General Partner of DCP Midstream Partners LP, from 2012 to 2014. Ms. Robeson also served as Group Vice President and Chief Financial Officer of DCP Midstream LLC from 2002 to 2012. Prior to her appointment as CFO of DCP Midstream LLC, Ms. Robeson was the Vice President and Treasurer at DCP, and previously served as Vice President and Treasurer at Kinder Morgan as well as in a number of finance and accounting positions at Total Petroleum (North America) Ltd. Ms. Robeson began her career primarily with Ernst & Young as a certified public accountant. We believe Ms. Robeson's extensive accounting, financial and executive management experience, and her prior experience with publicly traded partnerships, provide her with the necessary skills to be a member of the Board and a member of the Audit Committee. With respect to the Audit Committee, she also qualifies as an "audit committee financial expert."

Joseph W. Sutton was elected as a member of the Board in May 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Since 2000, Mr. Sutton has been the manager of Sutton Ventures Group, LLC, an energy investment firm that he founded. In 2007, he founded and has since led Consolidated Asset Management Services, or CAMS, which provides asset management, operations and maintenance, information technology, budgeting, contract management and development services to power plant ventures, oil and gas companies, renewable energy companies and other energy businesses. From 1992 to November 2000, Mr. Sutton worked for Enron Corporation, an energy company, where he most recently served as vice chairman and as chief executive officer of Enron International. We believe that Mr. Sutton's over 20 years of energy finance experience provide him with the necessary skills to be a member of the Board.

Lucius H. Taylor was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Taylor joined ArcLight in 2007. He has 16 years of experience in energy and natural resource finance and engineering. Prior to joining ArcLight, Mr. Taylor was a Vice President in the Energy and Natural Resource Group at FBR Capital Markets where he focused on raising public and private capital for companies in the power and energy sectors. Mr. Taylor began his career as a geologist and project manager at CH2M HILL, Inc., a global engineering, construction, and operations firm. Mr. Taylor earned a Bachelor of Arts in Geology from Colorado College, a Master of Science in Hydrogeology from the University of Nevada, and a Master of Business Administration from the Wharton School at the University of Pennsylvania. We believe that Mr. Taylor's 16 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Gerald A. Tywoniuk was elected as a member of the Board in May 2011. From May 2010 to the present, Mr. Tywoniuk has provided interim and project CFO services. He also currently serves as a director and audit committee chairperson on the board of the General Partner of Oxford Resource Partners, LP (NYSE:OXF) and serves as a director and audit committee member on the board of the General Partner of Landmark Infrastructure Partners LP (NASDAQ:LMRK). From June 2008 through August 2013, Mr. Tywoniuk served Pacific Energy Resources Ltd. in various senior roles (Senior Vice President, Finance beginning June 2008, Chief Financial Officer beginning August 2008, acting Chief Executive Officer and CFO beginning September 2009, Plan Representative beginning December 2010). He held these positions as an employee until May 2010 and as a consultant on a part-time basis until

August 2013. Pacific Energy Resources Ltd. was an oil and gas acquisition, exploitation and development company. Mr. Tywoniuk joined the company in June 2008 to help the management team work through the company's financially distressed situation. The board of the company elected to file for Chapter 11 protection in March 2009. In December 2009, the company completed the sale of its assets, and in August 2013 completed its liquidation. Prior to joining Pacific Energy Resources Ltd., Mr. Tywoniuk acted as an independent consultant in accounting and finance from March 2007 to June 2008. From December 2002 through November 2006, Mr. Tywoniuk was Senior Vice President and Chief Financial Officer of Pacific Energy Partners, LP. From November 2006 to March 2007, Mr. Tywoniuk assisted with the integration of Pacific Energy Partners, LP after it was acquired by Plains All American Pipeline, L.P. Mr. Tywoniuk holds a Bachelor of Commerce degree from The University of Alberta, Canada, and is a Canadian chartered accountant. Mr. Tywoniuk has 33 years of experience in accounting and finance, including 12 years as the Chief Financial Officer of three public companies and four years as Vice President/Controller of a fourth public company. Mr. Tywoniuk's extensive accounting, financial and executive management experience, and his prior experience with publicly traded partnerships, provide him with the necessary skills to be a member of the Board and a member and the chairman of the Audit Committee. With respect to the Audit Committee, he also qualifies as an "audit committee financial expert."

Family Relationships

There are no family relationships among any of the Partnership's directors and executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our General Partner's board of directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file with the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10% unitholders are required by the SEC's regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they file with the SEC.

Based solely upon a review of Forms 3 and 4, and amendments thereto, during fiscal 2014, the Partnership knows of no director, officer, or beneficial owner of more than 10% of any class of equity securities of the Company registered pursuant to Section 12 of the Exchange Act that failed to file timely any reports required to be furnished pursuant to Section 16(a) of the Exchange Act, other than with respect to:

Forms 4 reporting the vesting of restricted units for each of Mr. Mathews, Mr. Campbell, Mr. Rowland and Mr. Brock which were each filed nine days late.

A Form 4 reporting the purchase of common units by Mr. Kendall which was filed three days late.

Item 11. Executive Compensation

Our General Partner, under the direction of the Board is responsible for managing our operations and employs all of the employees that operate our business. The compensation payable to the officers of our General Partner is paid by our General Partner and such payments are reimbursed by us on a dollar-for-dollar basis.
The following is a discussion of the compensation policies and decisions of the Compensation Committee of the Board, with respect to the following individuals, who are executive officers of our General Partner and referred to as the "named executive officers" for the fiscal year ended December 31, 2014:

- Stephen W. Bergstrom, President and Chief Executive Officer;
- Daniel C. Campbell, Senior Vice President and Chief Financial Officer;
- Matthew W. Rowland, Senior Vice President and Chief Operating Officer;
- Kevin J. Sullivan, Executive Vice President;
- Robert W. Bourne, Senior Vice President of Business Development; and
- William B. Mathews, Secretary, Vice President of Legal Affairs and General Counsel.

Our compensation program is designed to recognize key managers are critical to our Partnership's profitability and growth. We utilize compensation to attract and retain management talent and to motivate key employees to focus consistently on growth and value creation. In addition, our compensation program aligns incentives for management and unitholders, focusing on long-term value creation rather than short-term gain. To do this, our compensation program for key managers is made up of the following main components: i) base salary, designed to compensate our executives for work performed during the fiscal year; ii) short-term incentive programs, designed to reward our executives for our yearly performance and for their individual performances during the fiscal year; and iii) equity-based awards, meant to align our executives interests with our long-term performance.
This section should be read together with the compensation tables that follow, which disclose the compensation awarded to, earned by or paid to the named executive officers with respect to the three years ended December 31, 2014.
Role of the Board, the Compensation Committee and Management

The Board has appointed the Compensation Committee to assist the Board in discharging its responsibilities relating to compensation matters, including matters relating to compensation programs for directors and executive officers of the General Partner. The Compensation Committee has overall responsibility for evaluating and approving our compensation plans, policies and programs, setting the compensation and benefits of executive officers, and granting awards under and administering our equity compensation plans. The Compensation Committee is charged with, among other things, establishing compensation practices and programs that are i) designed to attract, retain and motivate exceptional leaders, ii) structured to align compensation with our overall performance and growth in distributions to unitholders, iii) implemented to promote achievement of short-term and long-term business objectives consistent with our strategic plans, and iv) applied to reward performance.

As described in further detail below under "— Elements of the Compensation Programs," the compensation programs for our executive officers consist of base salaries, annual incentive bonuses and awards under the American Midstream GP, LLC, Long-Term Incentive Plan, which we refer to as our LTIP, currently in the form of equity-based phantom units, as well as other customary employment benefits such as a 401(k) plan, and health and welfare benefits. We expect that total compensation of our executive officers and the components of compensation and allocation among components of their annual compensation will be reviewed on at least an annual basis by the Compensation Committee.

During 2014, the Compensation Committee discussed executive compensation issues at several meetings, and the Compensation Committee expects to hold additional executive compensation-related meetings in 2015 and future years. Topics discussed and to be discussed at these meetings included and will include, among other things, i) assessing the performance of the Chief Executive Officer, or the CEO, with respect to our results for the prior year, ii) reviewing and assessing the personal performance of the executive officers and other key managers for the preceding year and iii) determining the amount of the bonus pool to be paid to our executives and other key managers for a given year after taking into account the target bonus amounts established for those executives and other key managers at the outset of the year. In addition, at these meetings, and after taking into account the recommendations of our CEO only with respect to executive officers and key managers other than our CEO, base salary levels and target bonus amounts (representing the bonus that may be awarded expressed as a dollar amount or as a percentage of base salary for the year) for our executive officers will be established by the Compensation Committee. In addition, the Compensation Committee will make its decisions with respect to any awards under the LTIP and recommended awards to the Board. Our CEO will provide periodic recommendations to the Compensation Committee regarding the performance and compensation of the other named executive officers as well as the amounts allocated to the short-term incentive plan and LTIP compensation pools.

Compensation Objectives and Methodology

The principal objective of our executive compensation program is to attract and retain individuals of demonstrated competence, experience and leadership who share our business aspirations, values, ethics and culture. A further objective is to provide incentives to and reward our executive officers and other key employees for positive contributions to our business and operations, and to align their interests with our unitholders' interests.

In setting our compensation programs, we consider the following objectives:

- to create unitholder value through sustainable earnings and cash available for distribution;
- to provide a significant percentage of total compensation that is "at-risk" or variable;
- to encourage significant equity holdings to align the interests of executive officers and other key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship, cooperation and executive compensation.

Taking account of the foregoing objectives, we structure total compensation for our executives to provide a guaranteed amount of cash compensation in the form of base salaries, while also providing a meaningful amount of annual cash compensation that is at risk and dependent on our performance and individual performance of the executives, in the form of discretionary annual bonuses. We also seek to provide a portion of total compensation in the form of equity-based awards under our LTIP, in order to align the interests of executives and other key employees with those of our unitholders and for retention purposes.

Compensation decisions for individual executive officers are the result of the subjective analysis of a number of factors, including the individual executive officer's experience, skills or tenure with us and changes to the individual executive officer's position. In evaluating the contributions of executive officers and our performance, although no pre-determined numerical goals were established, a variety of financial measures have been generally considered, including non-GAAP financial measures used by management to assess our financial performance, such as adjusted EBITDA and cash available for distribution. For a definition of adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use adjusted EBITDA to evaluate our operating performance, please read "Management's Discussion and Analysis —How We Evaluate Our Operations." In addition, a variety of factors related to the individual performance of the executive officer were taken into consideration.

In making individual compensation decisions, the Compensation Committee historically has not relied on pre-determined performance goals or targets. Instead, determinations regarding compensation have resulted from the exercise of judgment based on all reasonably available information and, to that extent, were discretionary. The amount of each executive officer's current compensation will be considered as a base against which determinations are made as to whether increases are appropriate to retain the executive officer in light of competition or in order to provide continuing performance incentives. Subject to the provisions contained in the executive officer's employment agreement, if any, the Compensation Committee has discretion to adjust any of the components of compensation to achieve our goal of recruiting, promoting and retaining executive officers and key individuals with the skills necessary to execute our business strategy and develop, grow and manage our business.

The Compensation Committee has also utilized benchmarking compensation levels across a range of publicly traded Master Limited Partnerships operating in the midstream market to inform specific award levels for Named Executive Officers and key managers. Going forward, we expect that the Compensation Committee will make compensation decisions taking into account trends occurring within our industry, including from a peer group of companies, which we expect will include, but not be limited to, the following similar publicly traded partnerships: Atlas Pipeline Partners LP, Blueknight Energy Partners LP, Crestwood Midstream Partners LP, Eagle Rock Energy Partners LP, Genesis Energy LP, JP Energy Partners LP, Martin Midstream Partners LP, QEP Midstream Partners LP, and Rose Rock Midstream, LP.

Elements of the Compensation Programs

Overall, the executive officer compensation programs are designed to be consistent with the philosophy and objectives set forth above. The principal elements of our executive officer compensation programs are summarized in the table below, followed by a more detailed discussion of each compensation element.

| Element | Characteristics | Purpose |
|---|---|---|
| Base Salaries | Fixed annual cash compensation. Executive officers are eligible for periodic increases in base salaries. Increases may be based on performance or such other factors as the Compensation Committee may determine. | Keep our annual compensation competitive with the defined market for skills and experience necessary to execute our business strategy. |
| Annual Incentive Bonuses | Performance-related annual cash incentives earned based on our objectives and individual performance of the executive officers. Increases or adjustments may be made based on both company and individual performance or such factors as the Compensation Committee may determine. | Align performance to our objectives that drive our business and reward executive officers for achieving our yearly performance objectives and for their individual contributions to these objectives during the fiscal year. |
| Equity-Based Awards (Phantom-units and Distribution Equivalent Rights) | Performance-related, equity-based awards granted at the discretion of the Compensation Committee. Awards are based on our performance and we expect that, going forward, and take into account competitive practices at peer companies. Grants typically consist of phantom units that vest ratably over four years and may be settled upon vesting with either a net cash payment or an issuance of common units, at the discretion of the Board. Historically, the Board has issued common units upon vesting of phantom units. Distribution Equivalent Rights, or DERs, have not been granted as part of the 2014 LTIP, but future awards may be eligible for DERs at the discretion of the Compensation Committee and approval by the Board. | Align interests of executive officers with unitholders and motivate and reward executive officers to increase unitholder value over the long term. Ratable vesting over a four-year period is designed to facilitate retention of executive officers. Issuance of common units upon vesting encourages equity ownership in order to align interests of executive officers with those of unitholders. |
| Retirement Plan | Qualified retirement plan benefits are available for our executive officers and all other regular full-time employees. At our formation, we adopted and are maintaining a tax-deferred or after-tax 401(k) plan in which all eligible employees can elect to defer compensation for retirement up to IRS imposed limits. The 401(k) plan permits us to make annual discretionary matching contributions | Provide our executive officers and other employees with the opportunity to save for their future retirement. |

| | | |
|---|---|---|
| | to the plan. For 2014, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 5% of the employee's eligible compensation. | |
| Health and Welfare Benefits | Health and welfare benefits (medical, dental, vision, disability insurance and life insurance) are available for our executive officers and all other regular full-time employees. | Provide benefits to meet the health and wellness needs of our executive officers, other employees and their families. |

Base Salaries

Base salaries for our executive officers will be determined annually by an assessment of our overall financial and operating performance, each executive officer's performance evaluation and changes in executive officer responsibilities. While many aspects of performance can be measured in financial terms, senior management will also be evaluated in areas of performance that are more subjective. These areas include development and execution of strategic plans, leading the development of management and other employees, innovation and improvement in our business activities and each executive officer's involvement in industry groups and in the communities that we serve. We seek to compensate executive officers for their performance throughout the year with annual base salaries that are fair and competitive within our marketplace. We believe that executive officer base salaries should be competitive with salaries for executive officers in similar positions and with similar responsibilities in our marketplace and adjusted for financial and operating performance and each executive officer's performance evaluation, length of service with us and previous work experience. Individual salaries have historically been established by the Compensation Committee based on the general industry knowledge and experience of its members, in alignment with these considerations, to ensure the attraction, development and retention of superior talent. Going forward, we expect that salary decisions will continue to focus on the above considerations and will also take into account relevant market data, including the market data and peer group data.

We expect that base salaries will be reviewed annually to ensure continuing consistency with market levels and our level of financial performance during the previous year. Future adjustments to base salaries and salary ranges will reflect movement in the competitive market as well as individual performance. Annual base salary adjustments, if any, for the CEO will be determined by the Compensation Committee. Annual base salary adjustments, if any, for the other executive officers will be determined by the Compensation Committee, taking into account input from the CEO.

The Compensation Committee approved the following base salaries for 2014 for the named executive officers as provided in the table below.

| Name | Base Salary at the end of 2014 |
|---|---|
| Stephen W. Bergstrom (a) | nm |
| Daniel C. Campbell | 285,000 |
| Matthew W. Rowland | 285,000 |
| Kevin J. Sullivan | 240,000 |
| Robert W. Bourne | 240,000 |
| William B. Mathews | 245,000 |

(a) Mr. Bergstrom was compensated in 2014 through an agreement with HPIP, the majority owner of our General Partner. Accordingly, during 2014 Mr. Bergstrom allocated time to HPIP and our General Partner on matters not related to the Partnership, none of which is considered compensation for services rendered in conjunction with his role as President and CEO of the Partnership.

(b) Messrs. Sullivan and Bourne base salaries were compensated by Costar Midstream Energy, LLC prior to being employed by our General Partner in October 2014.

nm Not meaningful

Annual Incentive Bonuses

As one way of accomplishing compensation objectives, executive officers are rewarded for their contribution to our financial and operational success through the award of discretionary annual cash incentive bonuses. Annual cash incentive awards, if any, for the CEO are determined by the Compensation Committee. Annual cash incentive awards, if any, for the other executive officers are determined by the Compensation Committee taking into account input from the CEO.

We expect to review cash bonus awards for the named executive officers annually to determine award payments for the prior fiscal year, as well as to establish target bonus amounts for the current fiscal year. At the beginning of each year, the Compensation Committee meets with the CEO to discuss partnership and individual goals for the year and what each executive is expected to contribute in order to help the partnership achieve those goals. However, the amounts of the annual bonuses have been and are determined at the discretion of the Compensation Committee with input from the CEO.

While target bonuses for our executive officers who have entered into employment agreements have been initially set at dollar amounts that are 75% to 100% of their base salaries, the Compensation Committee has had broad discretion to retain, reduce or increase the award amounts when making its final bonus determinations. Bonuses (similar to other elements of the compensation provided to executive officers) historically have not been solely based on a prescribed formula or pre-determined goals, specified performance targets but rather have been determined on a discretionary basis and generally have been based on a subjective evaluation of individual, company-wide and industry performances. Target bonus amounts for 2014 for all of the executive officers, which are specified in their employment agreements, are set forth in the table below. Please refer to "—Employment Agreements with Named Executive Officers" below for a description of the employment agreements.

The Board and the Compensation Committee believe that this approach to assessing performance results in a more comprehensive evaluation for compensation decisions. In 2014, the Compensation Committee recognized the following factors in making discretionary annual bonus recommendations and determinations:

- a subjective company performance evaluation based on company-wide financial performance including actual EBITDA versus budgeted EBITDA to assess company performance and adjusted as needed for new acquisitions and major capital programs in 2014;
- a subjective individual performance evaluation for executive officers and other factors the CEO may deem relevant; and
- the scope, level of expertise and experience required for the executive officer's position.

These factors were selected as the most appropriate measures upon which to base the annual incentive cash bonus decisions because our Compensation Committee believes that they help to align individual compensation with performance and contribution. With respect to its evaluation of company-wide financial performance, although no pre-determined numerical goals are established, the Compensation Committee generally reviewed our results with respect to adjusted EBITDA as compared to operating budget and cash available for distribution in making annual bonus determinations.

Following its performance assessment, and based on our financial performance with respect to these criteria and the Compensation Committee's qualitative assessment of individual performance, the Compensation Committee determines to award the base salary and incentive bonus amounts, which may be paid in cash or common units, set forth in the table below to our named executive officers for performance in 2014.

| Name | 2014 Base Salary | 2014 Target Bonus | 2014 Bonus Earned |
|---|---|---|---|
| Stephen W. Bergstrom | nm | $— | $— |
| Daniel C. Campbell | 285,000 | 213,750 | 271,000 |
| Matthew W. Rowland | 285,000 | 213,750 | 159,200 |
| Kevin J. Sullivan (a) | 240,000 | — | — |
| Robert W. Bourne (a) | 240,000 | — | — |
| William B. Mathews | 245,000 | 183,750 | 147,000 |

(a) Messrs. Sullivan and Bourne base salaries were compensated by Costar Midstream Energy, LLC prior to being employed by our General Partner in October 2014. 2014 Bonuses earned were paid in their entirety by Costar Midstream Energy, LLC. as disclosed below. Due to the timing of their employment by our General Partner, they were not eligible for 2014 bonuses paid in 2015.

Beginning in 2014, the Compensation Committee expected that it would determine base annual incentive compensation award recommendations on additional company-wide criteria as well as industry criteria, recognizing the following factors as part of its determination of annual incentive bonuses (without assigning any particular weighting to any factor):

- financial performance for the prior fiscal year, including adjusted EBITDA and cash available for distribution;
- distribution performance for the prior fiscal year;
- unitholder total return for the prior fiscal year; and
- competitive compensation data of executive officers.

These factors were selected as the most appropriate measures upon which to base the annual cash incentive bonus decisions going forward because the Compensation Committee believes that they will most directly correlate to increases in long-term value for our unitholders.

Equity-Based Awards

Design. The LTIP was adopted in 2009 in connection with our formation and most recently amended and restated in 2012. In adopting the LTIP, the Board recognized that it needed a source of equity to attract new members to and retain members of the management team, as well as to provide an equity incentive to other key employees and non-employee directors. We believe the LTIP promotes a long-term focus on results and aligns executive and unitholder interests. As part of this initial formation, we granted phantom units with associated DERs to provide long-term incentives to our named executive officers. DERs enabled the recipients of phantom unit awards to receive cash distributions on our phantom units to the same extent generally as unitholders receive cash distributions on our common units. Units awarded as part of the 2014 LTIP will not be eligible for DERs. Future awards may be eligible for DERs. The CEO may recommend to the Compensation Committee the distribution of DERs associated with subsequent awards but payout of DERs must be approved by the Board.

The LTIP is designed to encourage responsible and profitable growth while taking into account non-routine factors that may be integral to our success. Long-term incentive compensation in the form of equity grants are used to provide incentives for performance that leads to enhanced unitholder value, encourage retention and closely align the executive officers' interests with unitholders' interests. Equity grants provide a vital link between the long-term results achieved for our unitholders and the rewards provided to executive officers and other key employees.

Phantom Units. The only awards made under the LTIP since its adoption have been phantom units. A phantom unit is a notional unit granted under the LTIP that entitles the holder to receive an amount of cash equal to the fair market value of one common unit upon vesting of the phantom unit, unless the Board elects to pay such vested phantom unit with a common unit in lieu of cash. Historically, our Board has always issued common units instead of cash. Unless an individual award agreement provides otherwise, the LTIP provides that unvested phantom units are forfeited at the time the holder terminates employment or board membership, as applicable. The terms of the award agreements of our named executive officers provide that a termination due to death or long-term disability results in full acceleration of vesting. In general, phantom units awarded under our LTIP vest as to 25% of the award on each of the first four anniversaries of the date of grant.

Equity-Based Award Policies. The LTIP is administered by the board of directors of our General Partner. The board of directors of our General Partner, at its discretion, may elect to settle such vested phantom units with a number of units equivalent to the fair market value at the date of vesting in lieu of cash. Although our General Partner has the option to settle in cash upon the vesting of phantom units, our General Partner has not historically settled these awards in cash. Although other types of awards are contemplated under the LTIP, the only currently outstanding awards are phantom units without DERs.
Generally, grants issued under the LTIP vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment. Ownership in the awards is subject to forfeiture until the vesting date.

Deferred Compensation. Tax-qualified retirement plans are a common way that companies assist employees in preparing for retirement. We provide our eligible executive officers and other employees with an opportunity to save for their retirement by participating in our 401(k) savings plan. The 401(k) plan allows executive officers and other employees to defer compensation (up to IRS imposed limits) for retirement and permits us to make annual discretionary matching contributions to the plan. For 2014, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 5% of the employee's eligible compensation. Decisions regarding this element of compensation do not impact any other element of compensation.

Other Benefits. Each of the named executive officers is eligible to participate in our employee benefit plans which provide for medical, dental, vision, disability insurance and life insurance benefits, which are provided on the same terms as available generally to all salaried employees. In 2014 and 2013, no perquisites were provided to the named executive officers.
Recoupment Policy. We currently do not have a recoupment policy applicable to annual incentive bonuses or equity awards. The Compensation Committee expects to continue to evaluate the need to adopt such a policy in 2015, in light of current legislative policies as well as economic and market conditions.
Employment and Severance Arrangements. The Board and the Compensation Committee consider the maintenance of a sound management team to be essential to protecting and enhancing our best interests. To that end, we recognize that the uncertainty that may exist among management with respect to their "at-will" employment with our General Partner may result in the departure or distraction of management personnel to our detriment. Accordingly, our General Partner previously entered into employment agreements with each of Messrs. Campbell and Rowland, which contain severance arrangements that we believed were appropriate to encourage the continued attention and dedication of members of our management. These employment agreements are described more fully below under "— Existing Employment Agreements with Named Executive Officers."

Summary Compensation Table for the Three Years ended December 31, 2014

The following table sets forth certain information with respect to the compensation paid to the named executive officers for the three years ended December 31, 2014.

| | Year | Salary | Bonus | Unit Awards (a) | All Other Compensation | Total Compensation |
|---|---|---|---|---|---|---|
| Stephen W. Bergstrom | 2014 | nm | $— | $— | $— | $— |
| Executive Chairman, President and Chief Executive Officer | 2013 | nm | — | — | — | — |
| | 2012 | | | | | |
| Daniel C. Campbell | 2014 | 285,000 | 250,000 | 352,492 | — | 887,492 |
| Senior Vice President and Chief Financial Officer | 2013 | 235,000 | 132,000 | 213,230 | — | 580,230 |
| | 2012 | 162,692 | — | 214,000 | — | 376,692 |
| Matthew W. Rowland | 2014 | 285,000 | 250,000 | 352,492 | — | 887,492 |
| Senior Vice President and Chief Operating Officer | 2013 | 122,577 | — | 527,000 | — | 649,577 |
| | 2012 | | | | | |
| Kevin J. Sullivan (b) | 2014 | 240,000 | 150,000 | — | — | 390,000 |
| Executive Vice President | 2013 | 240,000 | 120,000 | — | — | 360,000 |
| | 2012 | 215,000 | — | — | — | 215,000 |
| Robert W. Bourne (b) | 2014 | 240,000 | 150,000 | — | — | 390,000 |
| Senior Vice President of Business Development | 2013 | 240,000 | 120,000 | — | — | 360,000 |
| | 2012 | 240,000 | — | — | — | 240,000 |
| William B. Mathews | 2014 | 245,000 | 150,000 | 236,593 | — | 631,593 |
| Vice President Legal Affairs, General Counsel and Secretary | 2013 | 215,750 | — | 214,500 | — | 430,250 |
| | 2012 | 215,000 | 91,000 | — | — | 306,000 |

(a) Amounts shown in this column do not reflect dollar amounts actually received by our named executive officers. Instead, these amounts reflect the aggregate grant date fair value of each phantom unit awards granted in each of the three years ended December 31, 2014, computed in accordance with the provisions of Financial Accounting Standards Board Accounting Standards Codification Topic 718, Compensation — Stock Compensation ("FASB ASC Topic 718"). Assumptions used in the calculation of these amounts are included in Note 16 "Long-term Incentive Plan" to our audited consolidated financial statements included in this Form 10-K.

(b) Messrs. Sullivan and Bourne base salaries were compensated by Costar Midstream Energy, LLC prior to being employed by our General Partner in October 2014. 2014 Bonuses earned were paid in their entirety by Costar Midstream Energy, LLC.

Grants of Plan-Based Awards for 2014

| Name | Grant Date | Estimated Future Payouts Under Equity Incentive Plan Awards Threshold # | Target # | Maximum # | Grant Date Fair Value of Unit Awards ($) |
|---|---|---|---|---|---|
| Stephen W. Bergstrom | — | — | — | — | $— |
| Daniel C. Campbell | 02/19/2014 | — | — | 14,848 | 352,492 |
| Matthew W. Rowland | 02/19/2014 | — | — | 14,848 | 352,492 |

| | | | | | |
|---|---|---|---|---|---|
| Kevin J. Sullivan | — | — | — | — | — |
| Robert W. Bourne | — | — | — | — | — |
| William B. Mathews | 02/19/2014 | — | — | 9,966 | 236,593 |

Employment Agreements with Named Executive Officers

Our General Partner has entered into employment agreements with certain of our named executive officers. Each of the employment agreements has an initial term of two years, which will be automatically extended for successive one year terms until either party elects to terminate the agreement by giving written notice at least 90 days prior to the end of the expiration of the initial or extended term, as applicable. The base salary and target bonus amounts set forth in such employment agreements are shown in the table below. The employment agreements provide that the base salary may be increased but not decreased (except for a decrease that is consistent with reductions taken generally by other executives of our General Partner). The agreements provide that the executive will be provided with the opportunity to earn an annual cash bonus, a certain percent of which will be conditioned and determined on the attainment of personal performance goals and the balance of which will be conditioned and determined on the attainment of organizational performance goals, in each case as set by, and based on performance criteria established by, the Compensation Committee. The employment agreements also provide that the executive may also be eligible to receive awards under the LTIP as determined by the Compensation Committee.

Each employment agreement also contains certain confidentiality covenants prohibiting each executive officer from, among other things, disclosing confidential information relating to our General Partner or any of its affiliates, including us. The employment agreements also contain non-competition and non-solicitation restrictions, which apply during the term of the executive's employment with our General Partner and, with certain exceptions, continue for a period of 12 months following termination for any reason.

The employment agreements also provide for, among other things, the payment of severance benefits under certain circumstances. Please refer to "— Potential Payment Upon Termination or Change in Control — Employment Agreements with Named Executive Officers" below for a description of these benefits under the employment agreements.

Outstanding Equity-Based Awards at December 31, 2014

The following table provides information regarding outstanding split adjusted equity-based awards held by the named executive officers as of December 31, 2014. All such equity-based awards consist of phantom units granted under the LTIP.

| | Unit Awards | |
|---|---|---|
| Name | Number of Phantom Units that Have Not Vested | Market Value of Phantom Units that Have Not Vested (a) |
| Stephen W. Bergstrom | — | — |
| Daniel C. Campbell | 18,078 | 356,317 |
| Matthew W. Rowland | 31,515 | 621,161 |
| Kevin J. Sullivan (b) | — | — |
| Robert W. Bourne (b) | — | — |
| William B. Mathews | 13,216 | 260,487 |

(a) The market value of phantom units that had not vested as of December 31, 2014, is calculated based on the fair market value of our common units as of December 31, 2014, which was $19.71 multiplied by the number of unvested phantom units. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates - Equity-Based Awards."

(b) Messrs. Sullivan and Bourne became employees of our General Partner in the acquisition of Costar Midstream in October 2014.

Units Vested in 2014
The following table shows the split adjusted phantom unit awards that vested during 2014.

| Name | 2014 Number of Units Acquired on Vesting | Fair Market Value per Unit Upon Vesting | Value Realized on Vesting (a) |
|---|---|---|---|
| Stephen W. Bergstrom | — | $— | $— |
| Daniel C. Campbell | | | |
| 03/01/2014 vest | 3,231 | $23.52 | $75,993 |
| 05/01/2014 vest | 5,000 | $27.07 | $135,350 |
| Matthew W. Rowland | | | |
| 08/22/2014 vest | 8,333 | $30.00 | $249,990 |
| Kevin J. Sullivan (b) | — | $— | $— |
| Robert W. Bourne (b) | — | — | — |
| William B. Mathews | | | |
| 03/01/2014 vest | 3,250 | $23.52 | $76,440 |
| 03/02/2014 vest | 3,130 | $23.52 | $73,618 |

(a) The value realized upon vesting of phantom units is calculated based on the fair market value of our common units at the applicable vesting date.

(b) Messrs. Sullivan and Bourne became employees of our General Partner in the acquisition of Costar Midstream in October 2014.

Long-Term Incentive Plan

The Board has adopted two LTIPs for employees, consultants and directors of our General Partner and affiliates who perform services for us. The plans provide for the issuance of options, unit appreciation rights, restricted units, phantom units, other unit-based awards, unit awards or replacement awards, as well as tandem DERs granted with respect to an award. To date, only phantom units, some with DERs, have been issued under the LTIPs. Currently, outstanding awards are phantom units without DERs.

As of December 31, 2014, 201,132 unvested phantom units were outstanding under our LTIPs. A phantom unit is a notional unit granted under the LTIPs that entitles the holder to receive an amount of cash equal to the fair market value of one common unit upon vesting of the phantom unit, unless the Board elects to pay such vested phantom unit with a common unit in lieu of cash. Historically, our Board has always issued common units in lieu of cash upon vesting of a phantom unit. DERs may be granted in tandem with phantom units. Except as otherwise provided in an award agreement, DERs that are not subject to a restricted period are currently paid to the participant at the time a distribution is made to the unitholders, and DERs that are subject to a restricted period are paid to the participant in a single lump sum no later than the 15th day of the third calendar month following the date on which the restricted period ends.

The number of units that may be delivered with respect to awards under the LTIPs may not exceed 1,175,352 units, subject to specified anti-dilution adjustments. However, if any award is terminated, canceled, forfeited or expires for any reason without the actual delivery of units covered by such award or units are withheld from an award to satisfy the exercise price or the employer's tax withholding obligation with respect to such award, such units will again be available for issuance pursuant to other awards granted under the LTIPs. In addition, any units allocated to an award will, to the extent such award is paid in cash, be again available for delivery under the LTIPs with respect to other awards. There is no limitation on the number of awards that may be granted under the LTIPs and paid in cash. The LTIPs provide that they are to be administered by the Board, provided that the Board may delegate authority to administer the LTIPs to a committee of non-employee directors. As of March 6, 2015, there are 368,594 units available for future grant awards.

The LTIPs may be terminated or amended at any time, including increasing the number of units that may be granted, subject to unitholder approval as required by the securities exchange on which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits of the participant without the consent of the participant. Each plan will terminate on the earliest of i) its termination by the Board or the Compensation Committee, ii) the tenth anniversary of the date the LTIP was adopted or iii) when units are no longer available for delivery pursuant to awards under the LTIP. Unless expressly provided for in the plan or an applicable award agreement, any award granted prior to the termination of the plan, and the authority of the Board or the Compensation Committee to amend, adjust or terminate such award or to waive any conditions or rights under such award, will extend beyond the termination date.

Potential Payments Upon Termination or Change in Control

Employment Agreements with Named Executive Officers

The employment agreements provide for, among other things, the payment of severance benefits following certain terminations of employment by our General Partner, the termination of employment for "Good Reason" (as defined below) by the executive officer, or, under certain circumstances, upon expiration of the term of the agreement. Under the employment agreements, if the executive's employment is terminated upon expiration of the initial or extended term of the agreement by either party upon 90 days' written notice (with certain exceptions, as described below), if the executive's employment is terminated by the General Partner other than for "Cause" (defined as defined below) or other than upon the executive's death or disability, or if the executive resigns for "Good Reason", the executive will have the right to severance in an amount equal to the sum of the executive's annual base salary at the rate in effect on the date of termination plus the amount, if any, paid to the executive as an annual cash bonus for the calendar year ending immediately prior to the date of such termination. Such severance amount will be paid in installments (on regular pay days scheduled in accordance with our regular payroll practices) beginning on the 60th day following the termination date and ending on the one year anniversary of the termination date, and will be subject to reimbursement by us to our General Partner. The foregoing severance benefit is conditioned on the executive executing a release of claims in favor of our General Partner and its affiliates, including us.

- "Cause": defined in each of the employment agreements as the executive having i) engaged in gross negligence, gross incompetence or willful misconduct in the performance of the duties required of him under the employment agreement, ii) refused without proper reason to perform the duties and responsibilities required of him under the employment agreement, iii) willfully engaged in conduct that is materially injurious to our General Partner or its affiliates including us (monetarily or otherwise), iv) committed an act of fraud, embezzlement or willful breach of fiduciary duty to our General Partner or an affiliate including us (including the unauthorized disclosure of confidential or proprietary material information of our General Partner or an affiliate including us) or v) been convicted of (or pleaded no contest to) a crime involving fraud, dishonesty or moral turpitude or any felony.

- "Good Reason": is defined in each employment agreement as a termination by the executive in connection with or based upon i) a material diminution in the executive's responsibilities, duties or authority, ii) a material diminution in the executive's base compensation, iii) assignment of the executive to a principal office located beyond a 50-mile radius of the executive's then current work place, or iv) a material breach by us of any material provision of the employment agreement.

Each employment agreement also contains certain confidentiality covenants prohibiting each executive officer from, among other things, disclosing confidential information relating to our General Partner or any of its affiliates, including us. The employment agreements also contain non-competition and non-solicitation restrictions, which apply during the term of the executive's employment with our General Partner and continue for a period of 12 months following termination for any reason. If the executive's employment is terminated upon expiration of the initial or extended term of the agreement by either party upon 90 days' written notice, the board of directors may, in its discretion, release the executive from being subject to the noncompetition covenant following termination of employment; however, in that case, the executive would not be entitled to receive any severance payment in connection with such termination.

Each of our named executive officers has received an award of phantom units under the LTIP. The terms of the phantom unit award agreements of our named executive officers provide that a termination due to death or disability results in full acceleration of vesting of any outstanding phantom units.

The following table shows the value of the severance benefits and other benefits for the named executive officers under the employment agreements and amended phantom unit grant agreements at December 31, 2014:

| Name | Benefit Type | Death or Disability(a) | Termination Without Cause, or Upon Expiration(b) | Resignation for Good Reason | Certain Changes of Control (a)(c) |
|---|---|---|---|---|---|
| Stephen W. Bergstrom | N/A | N/A | N/A | N/A | N/A |
| Daniel C. Campbell | Severance payment per employment agreement | None | $411,250 | $411,250 | 411,250 |
| | Accelerated vesting of phantom unit awards per award agreement | $310,300 | None | None | $310,300 |
| Matthew W. Rowland | Severance payment per employment agreement | None | $275,000 | $275,000 | None |
| | Accelerated vesting of phantom unit awards per award agreement | $677,000 | None | None | $677,000 |

(a) The amounts shown in this column are calculated based on the fair market value of our common units which we have assumed for this purpose will be $19.71, multiplied by the number of phantom units that would vest as of December 31, 2014.

(b) In connection with a termination of the executive's employment upon expiration of the initial or extended term of the agreement by either party pursuant to the terms of the employment agreement, the board of directors may, in its discretion, release the executive from being subject to the non-competition covenant following termination of employment; however, in such case, the executive would not be entitled to receive the severance payment.

(c) Pursuant to the amended phantom unit award agreements, accelerated vesting of phantom units would only occur under certain types of change of control transactions, as described under "— Amended Phantom Unit Grant Agreements" above.

Compensation of Directors

Compensation Committee Interlocks and Insider Participation

The Compensation Committee of the Board is comprised of Messrs. Bergstrom and Erhard as of December 31, 2014. Ms. Aptman served on the Compensation Committee prior to her resignation. The Compensation Committee makes compensation decisions regarding the executive officers of our General Partner. With the exception of Mr. Bergstrom, none of the members of the Compensation Committee is or has been one of our officers or employees, and none of our executive officers served during 2014 on a board of directors or compensation committee of another entity which has employed any of the members of our board of directors or compensation committee.

Director Fees

Each director who is not an officer or employee of our General Partner receives compensation for attending meetings of the Board, as well as committee meetings, as follows:

- a $50,000 annual cash retainer;
- a $50,000 annual unit grant;
- where applicable, a variable fee for service rendered as member of the Conflicts Committee to the board of directors; and
- where applicable, a committee chair retainer of $10,000 for each committee chaired.

In addition, each non-employee director will receive per meeting fees of:

- $1,000 for Board meetings attended in person;
- where applicable, $500 for Board committee meetings attended in person; and
- $500 for telephonic Board meetings and committee meetings greater than one hour in length.

Generally, non-employee directors listed in the table below are reimbursed for out-of-pocket expenses in connection with attending meetings of the Board or its committees. Each director will be fully indemnified by us for actions associated with being a director of our General Partner to the extent permitted under Delaware law.

Director Compensation Table for 2014

The following table sets forth the compensation paid to our non-employee directors for the year ended December 31, 2014, as described above. The compensation paid in 2014 to Mr. Bergstrom as an executive officer is set forth in the Summary Compensation Table above. Mr. Bergstrom did not receive any additional compensation related to his service as a director.

| | Fees Earned or Paid in Cash | Unit Awards (a) | All Other Compensation | Total Compensation |
|---|---|---|---|---|
| Eileen A. Aptman (b) | 33,000 | 45,910 | — | 78,910 |
| John F. Erhard | — | — | — | — |
| Donald R. Kendall Jr. | 61,750 | 74,667 | — | 136,417 |
| Daniel R. Revers | — | — | — | — |
| Rose M. Robeson (c) | 24,667 | 24,660 | — | 49,327 |
| Joseph W. Sutton | — | — | — | — |
| Lucius H. Taylor | — | — | — | — |
| Gerald A. Tywoniuk | 71,250 | 96,688 | — | 167,938 |

(a) The amount reported in this column represents the aggregate grant date fair value of the unit award granted during 2014.
(b) Ms. Aptman resigned her position as a member of the Board effective March 31, 2014.
(c) Ms. Robeson was appointed as a member of the Board in June 2014.

Compensation Committee Report

During 2014, the Compensation Committee of the Board was comprised of three directors (Messrs. Bergstrom and Erhard and Ms. Aptman, prior to her resignation).

The Compensation Committee has discussed and reviewed the above Compensation Discussion and Analysis for fiscal year 2014 with management. Based on this review and discussion, the Compensation Committee recommended to the Board that this Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year 2014.

Stephen W. Bergstrom
John F. Erhard

Compensation Practices as They Relate to Risk Management

We do not believe that our compensation policies and practices create risks that are reasonably likely to have a material adverse effect on the partnership. We believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees). Short-term annual incentives are generally paid pursuant to discretionary bonuses enabling the CEO and Compensation Committee to assess the actual behavior of our employees as it relates to risk taking in awarding a bonus. Our use of equity based long-term compensation serves our compensation program's goal of aligning the interests of executives and unitholders, thereby reducing the incentives to unnecessary risk taking.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth certain information regarding the beneficial ownership of units as of March 6, 2015 and the related transactions by:

- each person who is known to us to beneficially own 5% or more of such units to be outstanding;
- our General Partner;
- each of the directors and named executive officers of our General Partner; and
- all of the directors and executive officers of our General Partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders as the case may be.

Our General Partner is owned 95% by HPIP and 5% by AIM Midstream Holdings. ArcLight controls HPIP. AIM Universal Holdings, LLC, a Delaware limited liability ("AIM") holds an aggregate 84.4% indirect interest in AIM Midstream Holdings.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, common units subject to options or warrants held by that person that are currently exercisable or exercisable within 60 days of March 6, 2015, if any, are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

| Name of Beneficial Owner | Common Units Beneficially Owned | Percentage of Common Units Beneficially Owned | | Preferred Series A Units Beneficially Owned | Series B Units Beneficially Owned (a) | Percentage of Total Common and Preferred Series A and Series B Units Beneficially Owned | |
|---|---|---|---|---|---|---|---|
| ArcLight Capital Partners, LLC (b) | — | — | % | 5,909,349 | 1,277,772 | 24.0 | % |
| High Point Infrastructure Partners, LLC (b) | — | — | % | 5,909,349 | 1,277,772 | 24.0 | % |
| Energy Spectrum Securities Corp (c) | 6,468,529 | 28.4 | % | — | — | * | |
| Neuberger Berman LLC (d) | 2,225,624 | 9.8 | % | — | — | * | |
| Salient Capital Advisors, LLC (e) | 1,600,990 | 7.0 | % | — | — | * | |
| Oppenheimer Funds, Inc. (f) | 1,227,051 | 5.4 | % | — | — | * | |
| Goldman Sachs Asset Management, LP (g) | 1,187,024 | 5.2 | % | — | — | * | |
| Stephen W. Bergstrom (h) | — | * | | — | — | * | |
| Daniel C. Campbell (h) | 21,928 | * | | — | — | * | |
| William B. Mathews (h) | 33,138 | * | | — | — | * | |
| Matthew W. Rowland (h) | 11,311 | * | | — | — | * | |
| Kevin J. Sullivan (h)(i) | 661,743 | 2.9 | % | — | — | * | |
| Robert W. Bourne (i)(j) | 661,743 | 2.9 | % | — | — | * | |
| Daniel R. Revers (a) | — | * | | 5,909,349 | 1,277,772 | 24.0 | % |
| John F. Erhard (h) | — | * | | — | — | * | |
| Donald R. Kendall Jr. (h) | 14,347 | * | | — | — | * | |
| Rose M. Robeson (h) | 1,776 | * | | — | — | * | |
| Joseph W. Sutton (h) | — | * | | — | — | * | |
| Lucius H. Taylor (h) | — | * | | — | — | * | |
| Gerald A. Tywoniuk (h) | 10,982 | * | | — | — | * | |
| All directors and executive officers as a group (consisting of 14 persons) | 755,225 | 3.3 | % | 5,909,349 | 1,277,772 | 26.5 | % |

* An asterisk indicates that the person or entity owns less than one percent.

(a) The Series B Units are held by American Midstream GP, LLC, our General Partner, which is controlled by High Point Infrastructure Partners, LLC ("HPIP"), which is in turn controlled, indirectly, by ArcLight Capital Partners, LLC (“ArcLight Partners”). HPIP and ArcLight Capital Partners disclaim ownership of the Series B Units except to their extent of the pecuniary interest therein.

(b) ArcLight Capital Holdings, LLC (“ArcLight Holdings”) is the sole manager and member of ArcLight Partners. ArcLight Holdings is the investment adviser to ArcLight Energy Partners Fund V, L.P. (“Fund V”) and ArcLight PEF GP V, LLC (“Fund GP”) is the general partner of Fund V. HPIP is controlled by Fund V (collectively, HPIP, Fund V, Fund GP, ArcLight Holdings and ArcLight Partners are the “ArcLight Entities”). ArcLight Partners is the manager of the general partner of Fund V. Mr. Revers is a manager of ArcLight Holdings and a managing partner of ArcLight Partners and has certain voting and dispositive rights as a member of ArcLight Partners' investment committee. Fund V, through indirectly controlled subsidiaries, owns approximately 90% of the ownership interest in HPIP, which in turn owns 95% of the General Partner. As a result, the ArcLight Entities and Mr. Revers may be deemed to indirectly beneficially own the securities of the Issuer held by HPIP and the General Partner, but disclaim beneficial ownership except to the extent of their respective pecuniary interests therein. The address for this person or entity is 200 Claredon Street, 55th Floor, Boston, MA 02117.

(c) Energy Spectrum Securities Corporation ("ESSC") owns 100% of the issued and outstanding membership interest of Energy Spectrum VI, LLC, a Texas limited liability company ("ESLLC"), which serves as the general partner of Energy Spectrum Capital VI LP, a Delaware limited partnership ("ESCLP"), which serves as the general partner of Energy Spectrum Partners VI LP, a Delaware limited partnership ("ESP" and together with ESSC, ESLLC, and ESCLP, the "Energy Spectrum Entities"). ESP is the record holder of the common units and has a direct pecuniary interest in such common units. ESSC, ESLLC, and ESCLP beneficially own the common units for the purposes of Section 13(d) of the Exchange Act and have an indirect pecuniary interest in such common units. The address for this person or entity is 5956 Sherry Lane, Suite 900, Dallas, TX 75225. This information is based solely on information included in the Schedule 13G/A filed by the beneficial owner on October 24, 2014.

(d) The address for this person or entity is 605 Third Avenue, New York, NY 10158. This information is based solely on information included in the Schedule 13G/A filed by the beneficial owner on December 31, 2014.

(e) The address for this person or entity is 4265 San Felipe, 8th Floor, Houston, TX 77027. This information is based solely on information included in the Schedule 13G/A filed by the beneficial owner on February 11, 2015.

(f) The address for this person or entity is Two World Financial Center, 225 Liberty Street, New York, NY 10281. This information is based solely on information included in the Schedule 13G filed by the beneficial owner on February 3, 2015.

(g) The address for this person or entity is 200 West Street, New York, New York 10282. This information is based solely on information included in the Schedule 13G/A filed by the beneficial owner on February 12, 2015.

(h) The address for this person or entity is c/o American Midstream Partners, LP, 1400 16th Street, Suite 310, Denver, CO 80202.

(i) Mr. Sullivan is a member of Costar Midstream Energy LLC but disclaims beneficial ownership of such units except to the extent of his pecuniary interest therein. Of the 661,743 units held by Costar Midstream Energy LLC, 237,342 are currently being held in escrow and a subject to forfeiture to satisfy claims arising as a result of breaches of certain representations and warranties contained in that certain Purchase and Sale Agreement, dated as of October 13, 2014, by and between Costar Midstream Energy LLC, Energy Spectrum Partners VI LP and American Midstream, LLC. The address for this person or entity is c/o American Midstream Partners, LP, 1400 16th Street, Suite 310, Denver, CO 80202.

(j) Mr. Bourne is a member of Costar Midstream Energy LLC but disclaims beneficial ownership of such units except to the extent of his pecuniary interest therein. Of the 661,742 units held by Costar Midstream Energy LLC, 237,342 are currently being held in escrow and a subject to forfeiture to satisfy claims arising as a result of breaches of certain representations and warranties contained in that certain Purchase and Sale Agreement, dated as of October 13, 2014, by and between Costar Midstream Energy LLC, Energy Spectrum Partners VI LP and American Midstream, LLC. The address for this person or entity is c/o American Midstream Partners, LP, 1400 16th Street, Suite 310, Denver, CO 80202.

The percentage of units beneficially owned is based on a total of 22,753,974 common units, 5,909,349 Series A Units, and 1,277,772 Series B Units, as applicable, outstanding at March 6, 2015.

Securities Authorized for Issuance Under Equity Compensation Plans

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. On November 2, 2009, the board of directors of our General Partner adopted a long-term incentive plan for its employees, consultants and directors who perform services for it or its affiliates. On May 25, 2010, the board of directors of our General Partner adopted an amended and restated long-term incentive plan. On July 11, 2012, the board of directors of our General Partner adopted a second amended and restated long-term incentive plan ("LTIP") that effectively increased available awards by 871,750 units. At December 31, 2014, 2013 and 2012, there were 688,976, 855,089 and 920,193 units, respectively, available for future grant under the LTIP.

Item 13. Certain Relationships and Related Transactions and Director Independence

As of March 6, 2015, HPIP controlled and owned 95% of the General Partner of the Partnership, and AIM Midstream Holdings owned 5%, of our General Partner, which owned an approximate 1.3% General Partner interest in us and all of our incentive distribution rights. High Point Infrastructure Partners, LLC, holds 5,909,349 Series A convertible preferred and controls our General Partner, which holds 1,277,772 Series B Units. AIM Midstream Holdings owned 626,304 common units representing an 2.8% limited partner interest in us.

Distributions and Payments to our General Partner and its Affiliates

The following summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our formation, ongoing operation and any liquidation of the Partnership. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Distributions of available cash to our General Partner and its affiliates:

HPIP, as the holder of 5,909,349 Series A Units, is entitled to receive cumulative distributions consisting of cash and Series A PIK preferred units, prior to any other distributions made in respect of any other partnership interests (the "series A quarterly distribution") in accordance with our partnership agreement, as amended (the "partnership agreement"). With respect to the coupon conversion quarter (as defined in our partnership agreement) and all quarters thereafter, the series A quarterly distribution shall be paid entirely in cash in accordance with our partnership agreement. To the extent that any portion of a series A quarterly distribution to be paid in cash with respect to any quarter exceeds the amount of available cash for such quarter, an amount of cash equal to the available cash for such quarter will be paid to HPIP and the balance of such series A quarterly distribution shall be unpaid, constitute an arrearage and accrue interest.

After making the Series A convertible preferred quarterly distribution and paying any arrearage and accrued interest with respect to the Series A Units, we will distribute available cash from operating surplus for any quarter 98.7% to our common and Series B unitholders pro rata, including AIM Midstream Holdings, and 1.3% to our General Partner in respect of its general partnership interest and in respect of its 1,277,772 Series B Units, assuming it makes any capital contributions necessary to maintain its 1.3% General Partner interest in us. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, the holders of our incentive distribution rights will be entitled to increasing percentages of the distributions, up to 48.0% of the distributions above the highest target distribution level.

Payments to our General Partner and its affiliates
Our General Partner will not receive a management fee or other compensation for its management of us. However, we will reimburse our General Partner and its affiliates for all expenses incurred on our behalf. Our partnership agreement provides that our General Partner will determine the amount of these reimbursed expenses.
Withdrawal or removal of our General Partner
If our General Partner withdraws or is removed, its General Partner interest and its incentive distribution rights will either be sold to the new General Partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage
Upon our liquidation, our partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Ownership Interests of Certain Executive Officers and Directors of Our General Partner

HPIP controls and owns 95%, and AIM Midstream Holdings owns 5%, of our General Partner.

In addition to the approximate 1.3% General Partner interest in us, our General Partner owns the incentive distribution rights, which entitle the holder to increasing percentages, up to a maximum of 48.0%, of the cash we distribute in excess of $0.4125 per unit per quarter.

Agreements with Affiliates

We and other parties have or may enter into the various documents and agreements with certain of our affiliates, as described in more detail below. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm's-length negotiations.

Business Development Activity. For the years ended December 31, 2014, 2013 and 2012, our General Partner incurred approximately $1.2 million, $1.8 million and $0.4 million of costs associated with certain business development activities, respectively. If the business development activities result in a project that will be pursued and funded by the Partnership, we will reimburse our General Partner for the business development costs related to that project.

Affiliated Transactions. The High Point System, along with $15.0 million in cash, was contributed to us by HPIP in exchange for 5,142,857 Series A Units. Of the cash consideration paid by HPIP, approximately $2.5 million was used to pay certain transaction expenses of HPIP, and the remaining approximately $12.5 million was used to repay borrowings outstanding under the Partnership's former credit facility.

In January 2014, in connection with the acquisition of the Lavaca System, the Partnership issued 1,168,225 Series B Units to our General Partner. The net proceeds related to the issuance was $30.0 million.

In connection with the Blackwater Acquisition, our General Partner contributed the net assets of Blackwater, which were recorded at their historical book value of $22.7 million for consideration of $63.9 million, of which $27.7 million was accounted for as a cash distribution to the General Partner. The consideration also included 125,500 limited partner units, which were accounted for as a non-cash distribution to the General Partner at a fair value of $3.1 million.

On October 9, 2012, Blackwater entered into a Convertible Promissory Note (the "BWHD Note") with ArcLight Energy Partners Fund V, L.P. ("AL Fund V"), in the amount of $20.0 million. AL Fund V is a related party to the Partnership. The BWHD Note was paid off during the fourth quarter of 2013 as part of the Blackwater Acquisition.

Procedures for Review, Approval and Ratification of Related-Person Transactions

The Board has adopted a code of business conduct and ethics that provides that the board of directors of our General Partner or its authorized committee will periodically review all related-person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our General Partner or its authorized committee considers ratification of a related-person transaction and determines not to so ratify, the code of business conduct and ethics will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The Code of Ethics provides that, in determining whether to recommend the initial approval or ratification of a related-person transaction, the board of directors of our General Partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: i) whether there is an appropriate business justification for the transaction; ii) the benefits that accrue to us as a result of the transaction; iii) the terms available to unrelated third parties entering into similar transactions; iv) the impact of the transaction on director independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediate family member of a director is a partner, shareholder, member or executive officer); v) the availability of other sources for comparable products or services; vi) whether it is a single transaction or a series of ongoing, related transactions; and vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

The Code of Ethics described above was adopted in connection with the closing of our initial public offering, and as a result the transactions described above were not reviewed under such policy.

In addition, our partnership agreement provides for the Conflicts Committee, as delegated by the Board as circumstances warrant, to review conflicts of interest between us and our General Partner or between us and affiliates of our General Partner. If a matter is submitted to the Conflicts Committee, which will consist solely of independent directors, for their review and approval, the Conflicts Committee will determine if the resolution of a conflict of interest that has been presented to it by the board of directors of our General Partner is fair and reasonable to us. The members of the Conflicts Committee may not be executive officers or employees of our General Partner or directors, executive officers or employees of its affiliates. In addition, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders.

Item 14. Principal Accountant Fees and Services

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we were billed by PricewaterhouseCoopers LLP for tax, independent auditing and related services for each of the last two years:

| | Year Ended December 31, 2014 (in thousands) | 2013 |
|---|---|---|
| Audit fees (a) | $1,603 | $1,622 |
| Audit related fees (b) | — | — |
| Tax fees (c) | 573 | 286 |
| All other fees (d) | — | — |
| | $2,176 | $1,908 |

(a) Audit fees primarily represent professional services rendered in connection with the i) audits of our annual financial statements for the fiscal years 2014 and 2013, ii) quarterly reviews of our financial statements included in Forms 10-Q, iii) the audits of our FERC regulated assets for the fiscal years 2014 and 2013, and iv) those services normally provided in connection with the issuance of consents and other services related to SEC matters.

(b) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not under audit fees.

(c) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder K-1 statements as well as partnership tax compliance and tax planning.

(d) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the categories listed in the table above. No such services were rendered by PricewaterhouseCoopers LLP during the last two years.

Our Audit Committee approved the use of PricewaterhouseCoopers LLP as our independent registered public accounting firm to conduct the audit of our consolidated financial statements for the year ended December 31, 2014. All services provided by our independent auditor are subject to pre-approval by the Audit Committee. The Audit Committee is informed of each engagement of the independent auditor to provide services to us.

PART IV
Item 15. Exhibits and Financial Statement Schedules
(a)(1) Financial Statements
Our consolidated financial statements are included under Part II, Item 8 of the Annual Report. For a listing of these items and accompanying footnotes, see "Index to Financial Statements: Page F-1 of this Annual Report.
(a)(2) Financial Statement Schedules
All other schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto or will be filed within the required timeframe.
(a)(3) Exhibits

| | |
|---|---|
| 2.1 | Agreement and Plan of Merger by and among AL Blackwater, LLC, Blackwater Midstream Holdings LLC, American Midstream Partners, LP, and Blackwater Merger Sub, LLC, dated as of December 10, 2013 (incorporated by reference to Exhibit 2.1 to American Midstream Partners, LP, Form 8-K filed December 10, 2013 [File No. 001-35257]) |
| 2.2 | Limited Liability Company Unit Purchase and Sale Agreement by and between American Midstream, LLC, and ArcLight Energy Partners Fund V, L.P., dated January 22, 2014 (incorporated by reference to Exhibit 2.1 to American Midstream Partners, LP Form 8-K filed January 22, 2014 [File No. 001-35257]) |
| 2.3 | Purchase and Sale Agreement, dated July 11, 2014, by and among American Midstream, LLC and DCP LP Holdings, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed July 15, 2014 [File No. 001-35257]) |
| 2.4 | Purchase and Sale Agreement, dated October 13, 2014, by and among American Midstream, LLC, Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed October 15, 2014 [File No. 001-35257]). |
| 3.1 | Certificate of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form S-1 filed March 31, 2011 [File No. 333-173191]) |
| 3.2 | Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form 8-K filed August 15, 2013 [File No 001-35257]) |
| 3.3 | First Amendment to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form 8-K filed November 1, 2013 [File No. 001-35257]) |
| 3.4 | Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP. (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form 8-K filed February 4, 2014 [File No. 001-35257]) |
| 3.5 | Amendment No. 3 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, L.P., dated January 31, 2014 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 6, 2014 [File No. 001-35257]) |

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| 3.6 | Certificate of Formation of American Midstream GP, LLC (incorporated by reference to Exhibit 3.4 to American Midstream Partners, LP, Form S-1 filed March 31, 2011 [File No. 333-173191]) |

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|---|---|
| 3.7 | Second Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.2 to American Midstream Partners, LP Form 8-K filed April 19, 2013 [File No. 000-35257]) |
| 3.8 | Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP Form 8-K filed February 10, 2014 [File No.001-35257]) |
| 4.1 | Warrant to Purchase Common Units of American Midstream Partners, LP, dated February 5, 2014 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed February 10, 2014 [File No. 001-35257]) |
| 4.2 | Registration Rights Agreement, dated August 20, 2014, by and among American Midstream Partners, LP and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 20, 2014 [File No. 001-35257]) |
| 4.3 | Securities Agreement, dated October 13, 2014, by and among American Midstream Partners, LP, Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 15, 2014 [File No. 001-35257]) |
| 10.1 | Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among American Midstream Partners, LP, American Midstream, LLC, Blackwater Investments, Inc., Bank of America, N.A., Wells Fargo Bank, National Association, BBVA Compass, Capital One National Association, Citicorp North America, Inc., Comerica Bank, SunTrust Bank, Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and the lenders party thereto. (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed September 10, 2014 [File No. 001-35257]) |
| 10.2 | Second Amended and Restated American Midstream GP, LLC, Long-Term Incentive Plan (incorporated by reference to Exhibit 10.10 to American Midstream Partners, LP, Form 8-K filed July 17, 2012 [File No. 001-35257]) |
| 10.3 | Form of American Midstream Partners, LP Long-Term Incentive Plan Grant of Phantom Units (incorporated by reference to Exhibit 10.8 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.4 | Gas Processing Agreement between American Midstream (Louisiana Intrastate), LLC, and Enterprise Gas Processing, LLC, dated June 1, 2011 (incorporated by reference to Exhibit 10.9 to American Midstream Partners, LP Form S-1/A filed July 15, 2011 [File No. 333-173191]) |
| 10.5 | Firm Gas Gathering Agreement Between American Midstream (Seacrest) LP, and Contango Resources Company (incorporated by reference to Exhibit 10.10 to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191]) |
| 10.6 | Amendment to Firm Gas Gathering Agreement between American Midstream Offshore (Seacrest) LP (formerly Enbridge Offshore Pipelines [Seacrest[ L.P.), and Contango Operators, Inc. (formerly Contango Resources Company) dated as of August 1, 2008 (incorporated by reference to Exhibit 10.11 |

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| | to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191]) |
| 10.7 | Base Contract for Sale and Purchase of Natural Gas Between Exxon Gas & Power Marketing Company and Mid Louisiana Gas Transmission, LLC (incorporated by reference to Exhibit 10.12 to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191]) |
| 10.8 | Gas Processing Agreement Between American Midstream (Mississippi) LLC and Venture Oil and Gas, Inc. (incorporated by reference to Exhibit 10.13 to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191]) |

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| 10.9 | Gas Transportation Contract between Midcoast Interstate Transmission, Inc. and City of Decatur Utilities (incorporated by reference to Exhibit 10.14 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.10 | Amendment No. 1 to Gas Transportation Contract between Enbridge Pipelines (AlaTenn) Inc. and the City of Decatur, Alabama (incorporated by reference to Exhibit 10.15 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.11 | Natural Gas Pipeline Construction and Transportation Agreement between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.16 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191)) |
| 10.12 | First Amendment to Natural Gas Pipeline Construction and Transportation Agreement dated June 28, 2000 between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.17 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.13 | Natural Gas Pipeline Transportation Agreement between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.18 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.14 | First Amendment to Natural Gas Pipeline Transportation Agreement dated June 28, 2000 between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.19 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.15 | Gas Transport Contract between Enbridge Pipelines (AlaTenn), L.L.C., and the City of Huntsville (incorporated by reference to Exhibit 10.20 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.16 | Service Agreement between Enbridge Pipelines (Midla), L.L.C., and Enbridge Marketing (US), LP, dated September 1, 2008 (incorporated by reference to Exhibit 10.21 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.17 | Service Agreement between Enbridge Pipelines (Midla), L.L.C., and Enbridge Marketing (US), LP, dated September 1, 2008 (incorporated by reference to Exhibit 10.22 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.18 | Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC, and Enterprise Gas Processing, LLC, dated July 1, 2010 (incorporated by reference to Exhibit 10.23 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.19 | Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC, and Enterprise Gas Processing, LLC, dated November 1, 2010 (incorporated by reference to Exhibit 10.24 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 12.20 | Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC, and Enterprise Gas Processing, LLC, dated April 1, 2011 (incorporated by reference to Exhibit 10.25 to American Midstream Partners, LP, Form S-1/A filed June 30, 2011 [File No. 333-173191]) |

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| 10.21+ | Form of Amendment of Grant of Phantom Units Under the American Midstream Partners, LP, Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191]) |
| 10.22+ | Employment Agreement by and between American Midstream GP, LLC, and Daniel C. Campbell (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed April 16, 2012 [File No. 001-35257]). |

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| 10.23 | Purchase and Sale Agreement, dated May 25, 2012, by and between Quantum Resources A1, LP, QAB Carried WI, LP, QAC Carried WI, LP and Black Diamond Resources, LLC, collectively as Seller and Quantum Resources Management, LLC, and American Midstream Chatom Unit 1, LLC, American Midstream Chatom Unit 2, LLC, collectively as Buyer (incorporated by reference to Exhibit 10.3 to American Midstream Partners, LP, Amendment No. 1 to Form 10-Q filed November 13, 2012 [File No. 001-35257]). |
| 10.24 | Contribution Agreement by and between High Point Infrastructure Partners, LLC, and American Midstream Partners, LP, dated April 15, 2013 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed April 19, 2013 [File No. 001-35257]) |
| 10.25 | Equity Restructuring Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC, and High Point Infrastructure Partners, LLC, dated August 9, 2013 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed August 15, 2013 [File No. 001-35257]) |
| 10.26+ | Employment Agreement between Matthew W. Rowland and American Midstream GP, LLC, dated August 22, 2013 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed August 28, 2013 [File No. 001-35257]) |
| 10.27 | Series B PIK Unit Purchase Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC, and High Point Infrastructure Partners, LLC, dated January 22, 2014 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed January 22, 2014 [File No. 001-35257]) |
| 10.28 | First Amendment to Series B PIK Unit Purchase Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC, and High Point Infrastructure Partners, LLC, dated January 22, 2014 (incorporated by reference to Exhibit 10.2 to American Midstream Partners, LP, Form 8-K filed February 4, 2014 [File No. 001-35257]) |
| 10.29 | Construction and Field Gathering Agreement by and between HPIP Lavaca, LLC, and Penn Virginia Oil & Gas, L.P., dated January 31, 2014 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed February 4, 2014 [File No. 001-35257]) |
| 10.30 | Change of Control Severance Agreement, dated June 5, 2014, by and between American Midstream GP, LLC and Tom L. Brock (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2014 [File No. 001-35257]) |
| 10.31 | Common Unit Purchase Agreement, dated July 14, 2014, by and among American Midstream Partners, LP and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed Jul 15, 2014 [File No. 001-35257]) |
| 10.32 | Waiver of Condition and First Amendment to Common Unit Purchase Agreement, dated August 15, 2014 by<br>and among American Midstream Partners, LP and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 20, 2014 [File No. 001-35257]) |

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| 10.33 | Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among American Midstream Partners, LP, American Midstream, LLC, Blackwater Investments, Inc., Bank of America, N.A., Wells Fargo Bank, National Association, BBVA Compass, Capital One National Association, Citicorp North America, Inc., Comerica Bank, SunTrust Bank, Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed September 10, 2014 [File No. 001-35257]) |
| 21.1* | American Midstream Partners, LP, List of Subsidiaries |
| 23.1* | Consent of Independent Registered Public Accounting Firm |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934 |

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|---|---|
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934 |
| 32.1* | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2* | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| **101.INS | XBRL Instance Document |
| **101.SCH | XBRL Taxonomy Extension Schema Document |
| **101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| **101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |
| **101.LAB | XBRL Taxonomy Extension Label Linkbase Document |
| **101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |

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| * | Filed herewith |
| + | Management contract or compensatory plan arrangement |
| ** | Submitted electronically herewith. |

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

American Midstream Partners, LP
(Registrant)

By: /s/ Daniel C. Campbell

Daniel C. Campbell
Senior Vice President & Chief Financial Officer
(Principal Financial Officer)

Date: March 10, 2015

Pursuant to the requirements of the Securities Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on March 10, 2015.

| Signatures | Title |
|---|---|
| /s/ Stephen W. Bergstrom<br>Stephen W. Bergstrom | Director, Executive Chairman, President and Chief Executive Officer of American Midstream Partners, LP<br>(Principal Executive Officer) |
| /s/ Daniel C. Campbell<br>Daniel C. Campbell | Senior Vice President and Chief Financial Officer (Principal Financial Officer) |
| /s/ Tom L. Brock<br>Tom L. Brock | Vice President, Chief Accounting Officer and Corporate Controller of American Midstream Partners, LP (Principal Accounting Officer) |
| /s/ John F. Erhard<br>John F. Erhard | Director, American Midstream GP, LLC |
| /s/ Donald R. Kendall Jr.<br>Donald R. Kendall Jr. | Director, American Midstream GP, LLC |
| /s/ Daniel R. Revers<br>Daniel R. Revers | Director, American Midstream GP, LLC |
| /s/ Rose M. Robeson<br>Rose M. Robeson | Director, American Midstream GP, LLC |
| /s/ Joseph W. Sutton<br>Joseph W. Sutton | Director, American Midstream GP, LLC |
| /s/ Lucius H. Taylor<br>Lucius H. Taylor | Director, American Midstream GP, LLC |
| /s/ Gerald A. Tywoniuk<br>Gerald A. Tywoniuk | Director, American Midstream GP, LLC |

AMERICAN MIDSTREAM PARTNERS, LP

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Partners of American Midstream Partners, LP

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive income, changes in partners’ capital and noncontrolling interest and cash flows present fairly, in all material respects, the financial position of American Midstream Partners, LP (the "Partnership") and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) because a material weakness in internal control over financial reporting related to the Partnership’s guidelines not being precise enough in describing the level of review to be performed regarding the inputs, assumptions, and formulas used in spreadsheets existed as of that date. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the December 31, 2014 consolidated financial statements, and our opinion regarding the effectiveness of the Partnership’s internal control over financial reporting does not affect our opinion on those consolidated financial statements. The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our audits (which were integrated audits in 2014 and 2013). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

As described in Management's Annual Report on Internal Control over Financial Reporting, management has excluded Costar Midstream, LLC from its assessment of internal control over financial reporting as of December 31, 2014, because it was acquired by the Partnership in a purchased business combination during 2014. We have also excluded Costar Midstream, LLC from our audit of internal control over financial reporting. Costar Midstream, LLC is a wholly owned subsidiary whose total assets and total revenues represent 25% and 6%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.
/s/ PricewaterhouseCoopers LLP
Denver, Colorado
March 10, 2015

American Midstream Partners, LP, and Subsidiaries
Consolidated Balance Sheets
(In thousands, except unit amounts)

| | December 31, 2014 | 2013 |
|---|---|---|
| Assets | | |
| Current assets | | |
| Cash and cash equivalents | $499 | $393 |
| Accounts receivable | 4,924 | 6,822 |
| Unbilled revenue | 24,619 | 23,001 |
| Risk management assets | 688 | 473 |
| Other current assets | 15,502 | 7,497 |
| Current deferred tax asset | 3,086 | — |
| Current assets held for sale | 52 | 272 |
| Total current assets | 49,370 | 38,458 |
| Property, plant and equipment, net | 582,182 | 312,701 |
| Goodwill | 142,236 | 16,447 |
| Intangible assets, net | 106,306 | 3,682 |
| Investment in unconsolidated affiliates | 22,252 | — |
| Other assets, net | 13,117 | 9,064 |
| Noncurrent assets held for sale, net | 1,181 | 1,723 |
| Total assets | $916,644 | $382,075 |
| Liabilities and Partners' Capital | | |
| Current liabilities | | |
| Accounts payable | $20,326 | $3,261 |
| Accrued gas purchases | 14,326 | 17,386 |
| Accrued expenses and other current liabilities | 25,788 | 15,058 |
| Current portion of long-term debt | 2,908 | 2,048 |
| Risk management liabilities | 215 | 423 |
| Current liabilities held for sale | 12 | 114 |
| Total current liabilities | 63,575 | 38,290 |
| Risk management liabilities | — | 101 |
| Asset retirement obligations | 34,645 | 34,636 |
| Other liabilities | 126 | 191 |
| Long-term debt | 372,950 | 130,735 |
| Deferred tax liability | 8,199 | 4,749 |
| Noncurrent liabilities held for sale, net | — | 95 |
| Total liabilities | 479,495 | 208,797 |
| Commitments and contingencies (see Note 19) | | |
| Convertible preferred units | | |
| Series A convertible preferred units (5,745 thousand and 5,279 thousand units issued and outstanding as of December 31, 2014 and 2013, respectively) | 107,965 | 94,811 |
| Equity and partners' capital | | |
| General Partner Interests (392 thousand and 185 thousand units issued and outstanding as of December 31, 2014 and 2013, respectively) | (2,450) | 2,696 |
| Limited Partner Interests (22,670 thousand and 7,414 thousand units issued and outstanding as of December 31, 2014 and 2013, respectively) | 294,695 | 71,039 |
| Series B convertible units (1,255 thousand and zero units issued and outstanding as of December 31, 2014 and 2013, respectively) | 32,220 | — |

| | | |
|---|---|---|
| Accumulated other comprehensive income (loss) | 2 | 104 |
| Total partners' capital | 324,467 | 73,839 |
| Noncontrolling interests | 4,717 | 4,628 |
| Total equity and partners' capital | 329,184 | 78,467 |
| Total liabilities, equity and partners' capital | $916,644 | $382,075 |

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

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Operations
(In thousands, except per unit amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Revenue | $307,309 | $294,051 | $204,868 |
| Gain (loss) on commodity derivatives, net | 1,091 | 28 | 3,400 |
| Total revenue | 308,400 | 294,079 | 208,268 |
| Operating expenses: | | | |
| Purchases of natural gas, NGLs and condensate | 197,952 | 215,053 | 154,472 |
| Direct operating expenses | 45,702 | 32,236 | 17,183 |
| Selling, general and administrative expenses | 23,103 | 19,079 | 14,309 |
| Equity compensation expense | 1,536 | 2,094 | 1,783 |
| Depreciation, amortization and accretion expense | 28,832 | 30,002 | 21,287 |
| Total operating expenses | 297,125 | 298,464 | 209,034 |
| Gain (loss) on involuntary conversion of property, plant and equipment | — | 343 | (1,021) |
| Gain (loss) on sale of assets, net | (122) | — | 123 |
| Loss on impairment of property, plant and equipment | (99,892) | (18,155) | — |
| Operating income (loss) | (88,739) | (22,197) | (1,664) |
| Other income (expense): | | | |
| Interest expense | (7,577) | (9,291) | (4,570) |
| Other expense | (670) | — | — |
| Earnings in unconsolidated affiliates | 348 | — | — |
| Net income (loss) before income tax benefit | (96,638) | (31,488) | (6,234) |
| Income tax (expense) benefit | (557) | 495 | — |
| Net income (loss) from continuing operations | (97,195) | (30,993) | (6,234) |
| Discontinued operations | | | |
| Gain (loss) from operations of disposal groups, net of tax | (611) | (2,413) | (18) |
| Net income (loss) | (97,806) | (33,406) | (6,252) |
| Net income (loss) attributable to noncontrolling interests | 214 | 633 | 256 |
| Net income (loss) attributable to the Partnership | $(98,020) | $(34,039) | $(6,508) |
| | | | |
| General Partner's Interest in net income (loss) | $(1,279) | $(1,405) | $(129) |
| Limited Partners' Interest in net income (loss) | $(96,741) | $(32,634) | $(6,379) |
| | | | |
| Distribution declared per common unit (a) | $1.85 | $1.75 | $1.73 |
| Limited Partners' net income (loss) per common unit (See Note 4 and Note 15): | | | |
| Basic and diluted: | | | |
| Income (loss) from continuing operations | $(8.54) | $(7.15) | $(0.70) |
| Income (loss) from operations of disposal groups | (0.04) | (0.27) | — |
| Net income (loss) | $(8.58) | $(7.42) | $(0.70) |
| Weighted average number of common units outstanding: | | | |
| Basic and diluted | 13,472 | 7,525 | 9,113 |

(a) Declared and paid during the years ended December 31, 2014, 2013 and 2012.

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

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American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Comprehensive Income
(In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Net income (loss) | $(97,806) | $(33,406) | $(6,252) |
| Unrealized gain (loss) on postretirement benefit plan assets and liabilities | (102) | (247) | (64) |
| Comprehensive income (loss) | $(97,908) | $(33,653) | $(6,316) |
| Less: Comprehensive income (loss) attributable to noncontrolling interests | 214 | $633 | $256 |
| Comprehensive income (loss) attributable to Partnership | $(98,122) | $(34,286) | $(6,572) |

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

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Changes in Partners' Capital and Noncontrolling Interest
(In thousands)

| | General Partner Interests | Limited Partner Interests | Series B Convertible Units | Accumulated Other Comprehensive Income (loss) | Total Partners' Capital | Non controlling Interests |
|---|---|---|---|---|---|---|
| Balances at December 31, 2011 | $1,091 | $99,890 | $— | $ 415 | $101,396 | $— |
| Acquisition of noncontrolling interests | — | — | — | — | — | 7,407 |
| Net income (loss) | (129) | (6,379) | — | — | (6,508) | 256 |
| Unitholder contributions | 13 | — | — | — | 13 | — |
| Unitholder distributions | (322) | (15,748) | — | — | (16,070) | — |
| Net distributions to noncontrolling interests | — | — | — | — | — | (225) |
| LTIP vesting | (1,888) | 1,888 | — | — | — | — |
| Tax netting repurchase | — | (385) | — | — | (385) | — |
| Equity compensation expense | 1,783 | — | — | — | 1,783 | — |
| Other comprehensive income (loss) | — | — | — | (64) | (64) | — |
| Balances at December 31, 2012 | $548 | $79,266 | $— | $ 351 | $80,165 | $7,438 |
| Net income (loss) | (1,405) | (32,634) | — | — | (34,039) | 633 |
| Issuance of common units, net of offering costs | — | 54,853 | — | — | 54,853 | — |
| Unitholder contributions | 12,500 | — | — | — | 12,500 | — |
| Unitholder distributions | (623) | (21,628) | — | — | (22,251) | — |
| Unitholder distribution for acquisition of Blackwater | (30,702) | 3,052 | — | — | (27,650) | |
| Unitholder contribution of Blackwater net assets | 22,696 | — | — | — | 22,696 | |
| Fair value of Series A Units in excess of net assets received | (312) | (15,300) | — | — | (15,612) | |
| Net distributions to noncontrolling interests | — | — | — | — | — | (661) |
| Acquisition of noncontrolling interests | 37 | 1,993 | — | — | 2,030 | (2,782) |
| LTIP vesting | (2,067) | 2,067 | — | — | — | — |
| Tax netting repurchase | — | (630) | — | — | (630) | — |
| Equity compensation expense | 2,024 | — | — | — | 2,024 | — |
| Other comprehensive income (loss) | — | — | — | (247) | (247) | — |
| Balances at December 31, 2013 | $2,696 | $71,039 | $— | $ 104 | $73,839 | $4,628 |
| Net income (loss) | (1,279) | (96,741) | — | — | (98,020) | 214 |
| Issuance of common units, net of offering costs | — | 351,551 | — | — | 351,551 | — |

| | | | | | | |
|---|---|---|---|---|---|---|
| Issuance of Series B Units | — | — | 32,220 | — | 32,220 | — |
| Unitholder contributions | 5,678 | — | — | — | 5,678 | — |
| Unitholder distributions | (2,913) | (39,150) | — | — | (42,063) | — |
| Issuance and exercise of warrants | (7,164) | 7,164 | — | — | — | — |
| Net distributions to noncontrolling interests | — | — | — | — | — | (314) |
| Acquisition of noncontrolling interests | — | 21 | — | — | 21 | 189 |
| LTIP vesting | (824) | 1,067 | — | — | 243 | — |
| Tax netting repurchase | — | (256) | — | — | (256) | — |
| Equity compensation expense | 1,356 | — | — | — | 1,356 | — |
| Other comprehensive income (loss) | — | — | — | (102) | (102) | — |
| Balances at December 31, 2014 | $(2,450) | $294,695 | $32,220 | $ 2 | $324,467 | $4,717 |

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

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Cash Flows
(In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Cash flows from operating activities | | | |
| Net income (loss) | $(97,806) | $(33,406) | $(6,252) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation, amortization and accretion expense | 28,832 | 29,999 | 21,414 |
| Amortization of deferred financing costs | 2,212 | 1,334 | 716 |
| Amortization of weather derivative premium | 1,035 | 662 | — |
| Unrealized (gain) loss on derivative contracts, net | (595) | 1,505 | (992) |
| Non-cash compensation | 1,626 | 2,094 | 1,783 |
| Postretirement expense (benefit) | (45) | (73) | (88) |
| (Gain) loss on involuntary conversion of property, plant and equipment | — | (343) | 1,021 |
| (Gain) loss on sale of assets, net | 207 | 75 | (128) |
| Loss on impairment of property, plant and equipment | 99,892 | 18,155 | — |
| Loss on impairment of noncurrent assets held for sale | 673 | 2,400 | — |
| Deferred tax expense (benefit) | 213 | (847) | — |
| Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed: | | | |
| Accounts receivable | 13,067 | (790) | (740) |
| Unbilled revenue | 2,272 | (226) | 2,768 |
| Risk management assets and liabilities | (809) | (1,147) | (156) |
| Other current assets | (7,533) | (1,614) | 984 |
| Other assets, net | 6,049 | (823) | (57) |
| Accounts payable | (12,026) | (845) | 1,197 |
| Accrued gas purchases | (5,540) | 462 | (1,711) |
| Accrued expenses and other current liabilities | (9,149) | 769 | (943) |
| Asset retirement obligations | (1,030) | — | — |
| Other liabilities | (67) | (118) | (468) |
| Net cash provided by operating activities | 21,478 | 17,223 | 18,348 |
| Cash flows from investing activities | | | |
| Cost of acquisitions, net of cash acquired | (362,316) | — | (51,377) |
| Additions to property, plant and equipment | (96,998) | (27,196) | (11,705) |
| Proceeds from disposal of property, plant and equipment | 6,323 | 500 | 128 |
| Insurance proceeds from involuntary conversion of property, plant and equipment | — | 482 | 527 |
| Investment in unconsolidated affiliate | (12,000) | — | — |
| Proceeds from equity method investment, return of capital | 1,632 | — | — |
| Restricted cash | (8,511) | (2,000) | — |
| Net cash used in investing activities | (471,870) | (28,214) | (62,427) |
| Cash flows from financing activities | | | |
| Proceeds from issuance of common units to public, net of offering costs | 204,255 | 54,853 | — |
| Unitholder contributions | 5,588 | 13,075 | 13 |
| Unitholder distributions | (28,009) | (16,120) | (16,070) |

| | | | |
|---|---|---|---|
| Issuance of Series A Units | — | 14,393 | — |
| Issuance of Series B Units | 30,000 | — | — |
| Unitholder distributions for Blackwater Acquisition | — | (27,650) | — |
| Acquisition of noncontrolling interests | (8) | (752) | — |
| Net distributions to noncontrolling interests | (314) | (661) | (225) |
| LTIP tax netting unit repurchase | (256) | (630) | (385) |
| Deferred financing costs | (3,841) | (2,113) | (1,564) |
| Payments on other debt | (2,589) | (2,640) | — |
| Borrowings on other debt | 3,449 | 3,795 | — |
| Payments on loan to affiliate | — | (20,000) | — |
| Payments on bank loans | — | (34,730) | — |
| Borrowings on bank loans | — | 27,546 | — |
| Payments on long-term debt | (250,870) | (131,571) | (59,230) |
| Borrowings on long-term debt | 493,085 | 134,021 | 121,245 |
| Net cash provided by financing activities | 450,490 | 10,816 | 43,784 |
| Net increase (decrease) in cash and cash equivalents | 98 | (175) | (295) |
| Cash and cash equivalents | | | |
| Beginning of period | 401 | 576 | 871 |
| End of period | $499 | $401 | $576 |
| Supplemental cash flow information | | | |
| Interest payments, net | $6,726 | $6,416 | $3,185 |
| Supplemental non-cash information | | | |
| (Decrease) increase in accrued property, plant and equipment | $31,390 | $(5,181) | $6,968 |
| Receivable for reimbursable construction in progress projects | — | — | 141 |
| Net assets contributed by General Partner in the Blackwater Acquisition (See Note 3) | — | 22,121 | — |
| Net assets contributed by General Partner in exchange for the issuance of Series A Units (see Note 3) | — | 59,995 | — |
| Fair value of Series A Units in excess of net assets received | — | 15,612 | — |
| Accrued and in-kind unitholder distribution for Series A Units | 13,154 | 4,811 | — |
| In-kind unitholder distribution for Series B Units | 2,220 | — | — |
| Common unit issuance related to Costar Acquisition | 147,296 | — | — |

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

American Midstream Partners, LP, and Subsidiaries
Notes to Consolidated Financial Statements

1. Organization and Basis of Presentation

General

American Midstream Partners, LP (the "Partnership"), was formed on August 20, 2009 as a Delaware limited partnership for the purpose of operating, developing and acquiring a diversified portfolio of midstream energy assets. The Partnership's general partner, American Midstream GP, LLC (the "General Partner"), is 95% owned by High Point Infrastructure Partners, LLC ("HPIP") and 5% owned by AIM Midstream Holdings, LLC. We hold our assets in a series of wholly owned limited liability companies, a limited partnership and a corporation. Our capital accounts consist of notional general partner units and limited partner interests.

Nature of business

We are engaged in the business of gathering, treating, processing, and transporting natural gas, fractionating NGLs and storing specialty chemical products through our ownership and operation of twelve gathering systems, five processing facilities, three fractionation facilities, four marine terminal sites, three interstate pipelines and five intrastate pipelines. We also own a 66.7% non-operating interest in Main Pass Oil Gathering, LP ("MPOG"), a crude oil gathering and processing system, as well as a 50% undivided, non-operating interest in the Burns Point Plant, a natural gas processing plant. Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Maryland, Mississippi, North Dakota, Tennessee and Texas, provide critical infrastructure that links producer of natural gas, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. We currently operate more than 3,000 miles of pipelines that gather and transport over 1 Bcf/d of natural gas and operate approximately 1.7 million barrels of storage capacity across four marine terminal sites.

Basis of presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2014 and 2013, and results of operations, comprehensive income, changes in partners' capital and noncontrolling interest, and cash flows for the years ended December 31, 2014, 2013 and 2012.

We have prepared the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We have made reclassifications to amounts reported in prior period consolidated financial statements to conform with current year presentation. These reclassifications did not have an impact on net income for the period previously reported.

The financial results for the years ended December 31, 2013 and 2012 have been reclassified to present an asset group previously presented as held for sale as held and used.

The results of operations for acquisitions accounted for as business combinations have been included in the consolidated financial statements since their respective acquisition dates. See Note 3 "Acquisitions" for further information.

Transactions Between Entities Under Common Control

We may enter into transactions with our General Partner and affiliates whereby we receive a contribution of midstream assets or subsidiaries in exchange for consideration from the Partnership. We account for the net assets received using the historical book value of the asset or subsidiary being contributed or transferred as these are transactions between entities under common control. Our historical financial statements may be revised to include the results attributable to the assets contributed from our General Partner as if we owned such assets for all periods presented by the Partnership since either the change in control of our General Partner, effective April 15, 2013 or later.

Consolidation policy

The accompanying consolidated financial statements include accounts of American Midstream Partners, LP, and its controlled subsidiaries. All significant inter-company accounts and transactions have been eliminated in the preparation of the accompanying consolidated financial statements. We hold a 50% undivided interest in the Burns Point gas processing facility in which we are responsible for our proportionate share of the costs and expenses of the facility. Our consolidated financial statements reflect our proportionate share of the revenues, expenses, assets and liabilities of this undivided interest. In July 2012, the Partnership acquired an 87.4% undivided interest in the Chatom Processing and Fractionation facility (the "Chatom System"). In the fourth quarter of 2013, the Partnership acquired an additional 4.8% undivided interest in the Chatom System. Our consolidated financial statements reflect the accounts of the Chatom System since acquisition. The interests in the Chatom System held by non-affiliated working interest owners are reflected as noncontrolling interests in the Partnership's consolidated financial statements.

The Partnership accounts for its 66.7% non-operated interest in MPOG as an equity method investments under ASC 323, as the Partnership exercises significant influence but does not control nor is the primary beneficiary of MPOG.

Use of estimates

When preparing consolidated financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and assumptions are based on information available at the time such estimates and assumptions are made. Adjustments made with respect to the use of these estimates and assumptions often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of financial statements. Estimates and assumptions are used in, among other things, i) estimating unbilled revenues, product purchases and operating and general and administrative costs, ii) developing fair value assumptions, including estimates of future cash flows and discount rates, iii) analyzing long-lived assets, goodwill and intangible assets for possible impairment, iv) estimating the useful lives of assets and v) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Cash and cash equivalents

We consider all highly liquid investments with an original maturity of three months or less at the date of purchase to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

Allowance for doubtful accounts

We establish provisions for losses on accounts receivable when we determine that we will not collect all or part of an outstanding balance. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of December 31, 2014 and 2013, the Partnership recorded no allowances for losses on accounts receivable.

Inventory

Inventory includes natural gas liquids ("NGLs") product inventory. The Partnership records all product inventories at the lower of cost or market with a cost basis determined on a weighted average basis. Product inventories are included within Other current assets on the consolidated balance sheets.

Operational balancing agreements and natural gas imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of natural gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a natural gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in-kind through future receipt or delivery of natural gas. Natural gas imbalances are recorded as gas imbalances and classified within Other current assets or Other current liabilities on our consolidated balance sheets at cost which approximates fair value.

Derivative financial instruments

Our net income (loss) and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt, commodity prices and fractionation margins (the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). In an effort to manage the risks to unitholders, we use a variety of derivative financial instruments including swaps, collars and interest rate caps to create offsetting positions to specific commodity or interest rate exposures. In accordance with the authoritative accounting guidance, we record all derivative financial instruments in our consolidated balance sheets at fair value as current and long-term assets or liabilities on a net basis by counterparty. We record changes in the fair value of our derivative financial instruments in our consolidated statements of operations as follows:

- Commodity-based derivatives: "Total revenue"
- Corporate interest rate derivatives: "Interest expense"

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

The price assumptions we use to value our derivative financial instruments can affect net income (loss) for each period. We use published market price information where available, or quotations from over-the-counter, or OTC, market makers to find executable bids and offers. The valuations also reflect the potential impact of conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Fair value measurements

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

We use various assumptions and methods in estimating the fair values of our financial instruments. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of our various credit facilities approximate fair value, because the interest rates on these facilities are variable.

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

- Level 1 – Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs include quoted prices for similar assets and liabilities in active markets that are either directly or indirectly observable; and
- Level 3 – Inputs are unobservable and considered significant to fair value measurement.

We utilize a mid-market pricing convention, or the "market approach," for valuation for assigning fair value to our derivative assets and liabilities. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

Property, plant and equipment

We capitalize expenditures related to property, plant and equipment that have a useful life greater than one year for assets purchased or constructed; existing assets that are replaced, improved, or the useful lives of which have been extended; and all land, regardless of cost. Maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

We record property, plant, and equipment at its original cost, which we depreciate on a straight-line basis over its estimated useful life. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We record depreciation using the group method of depreciation, which is commonly used by pipelines, utilities and similar assets.

We classify long-lived assets to be disposed of through sales that meet specific criteria as held for sale. We cease depreciating those assets effective on the date the asset is classified as held for sale. We record those assets at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

Impairment of long lived Assets

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

Goodwill and intangible assets

We record goodwill for the excess of the cost of an acquisition over the fair value of the net assets of the acquired business. Goodwill is not amortized but is reviewed for impairment at least annually or more frequently if an event or change in circumstance indicates that an impairment may have occurred. We first assess qualitative factors to evaluate whether it is more likely than not that an impairment has occurred and it is therefore necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test indicates that the goodwill is impaired, an impairment loss is recorded.

We record the estimated fair value of acquired customer contracts, relationships and dedicated acreage agreements as intangible assets. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging between 5 months and thirty years. We assess intangible assets for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

Deferred financing costs

Costs incurred in connection with the issuance of long-term debt are deferred and charged to interest expense over the term of the related debt. Gains or losses on debt repurchase and debt extinguishment include any associated unamortized deferred financing costs.

Asset retirement obligations ("AROs")

AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and operation. An ARO is initially measured at its estimated fair value. Upon initial recognition, we also record an increase to the carrying amount of the related long-lived asset. We depreciate the asset using the straight-line method over the period during which it is expected to provide benefits. After initial recognition, we revise the ARO to reflect the passage of time and for changes in the estimated amount or timing of cash flows.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our offshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement of estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's experience, or the asset's estimated economic life. The useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

Commitments, contingencies and environmental liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur from the remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated.

Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulation taking into consideration the likely effects of inflation and other factors. These amounts also take into account our prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual cost or new information. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record an asset separately from the associated liability in our consolidated financial statements.

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

Noncontrolling interests

Noncontrolling interests represent the noncontrolling interest holders' proportionate share of the equity of the respective systems. Noncontrolling interest is adjusted for the noncontrolling interest holders' proportionate share of the earnings or losses. Management reports noncontrolling interest in the Chatom system in the financial statements pursuant to paragraph ASC 810-10-65-1. The 7.8% noncontrolling interest is held by non-affiliated working interest owners.

Revenue recognition and the estimation of revenues and cost of purchases

We recognize revenue when all of the following criteria are met: i) persuasive evidence of an exchange arrangement exists, ii) delivery has occurred or services have been rendered, iii) the price is fixed or determinable, and iv) collectability is reasonably assured. We record revenue and cost of product sold on a gross basis for those transactions where we act as the principal and take title to natural gas, NGLs or condensates that are purchased for resale. When our customers pay us a fee for providing a service such as gathering, treating, transportation or storage, we record those fees separately in revenues. We have the following arrangements:

Fee-based

Under these arrangements, we generally are paid a fixed fee for gathering and transporting natural gas. Fee-based revenues are recorded when services have been provided, and collectability of the revenue is reasonably assured.

Percent-of-proceeds, or POP

Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas and NGLs at market prices. Where we provide processing services at the processing plants that we own, or obtain processing service for our own account under our own elective processing arrangements we typically retain and sell a percentage of the residue natural gas and resulting NGLs. We recognize percent-of-proceeds contract revenue when the natural gas, NGLs or condensate is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured.

Fixed-margin

Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same, undiscounted index price. We recognize revenue from fixed-margin contracts when the natural gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured.

Firm transportation

Under arrangements to provide firm transportation service, we are obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not they utilize the capacity. In most cases, the shipper also pays a variable-use charge with respect to quantities actually transported by us. Firm transportation revenue is recorded when products are delivered, services have been provided, and collectability of the revenue is reasonably assured.

Interruptible transportation

Under arrangements to provide interruptible transportation service, we are only obligated to transport natural gas nominated by the shipper to the extent we have available capacity. For this service, the shipper pays no reservation charge but pays a variable-use charge for quantities actually shipped. Interruptible transportation revenue is recorded when products are delivered, services have been provided, and collectability of revenue is reasonably assured.

Interest in the Burns Point Plant

We account for our interest in the Burns Point Plant using the proportionate consolidation method. Under this method, we include in our consolidated statement of operations our value of plant revenues taken in-kind and plant expenses reimbursed to the operator.

Terminal revenue and services

Revenues for our terminals include storage tank lease fees, whereby a customer agrees to pay for a certain amount of tank storage over a certain period of time; and throughput fees, whereby a customer pays a fee based on volumes moving through the terminal. At our terminals, we also offer and provide packaging, blending, handling, filtering and certain other ancillary services. Revenue from firm storage contracts is recognized ratably, which is typically monthly, over the term of the lease. Occasionally, customers pay for tank lease fees in advance. Fees received in advance are deferred until the period earned. Revenue from throughput fees and ancillary fees are recognized as services are provided to the customer and collectability is reasonably assured.

Equity-based compensation

We award equity-based compensation to management, non-management employees and directors in the form of phantom units, which are deemed to be equity awards. Compensation expense on phantom units is measured by the fair value of the award at the date of grant as determined by management. Compensation expense is recognized in Equity compensation expense over the requisite service period of each award.

Income taxes

The Partnership is not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income are generally borne by our unitholders through the allocation of taxable income. American Midstream Blackwater, LLC, a subsidiary of the Partnership, owns a taxable C-Corporation consolidated return group which is a taxable entity. We account for income taxes of that subsidiary using an asset and liability approach for financial accounting and reporting of income taxes. If it is more than likely that a deferred tax asset will not be realized, a valuation allowance is recognized.

Certain tax expense results from the enactment of laws by the State of Texas that apply to entities organized as partnerships and is included in Income tax (expense) benefit in the consolidated statements of operations. The Texas margin tax is computed on our taxable margin apportioned to Texas annually.

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

Accumulated other comprehensive income (loss)

Accumulated other comprehensive income (loss) is comprised solely of adjustments related to the Partnership's postretirement benefit plan.

Limited partners' net income (loss) per unit

We compute earnings per unit using the two-class method. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the General Partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the General Partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The two-class method does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the General Partner, even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the two-class method does not have any impact on our calculation of earnings per limited partner unit. We have no dilutive securities, therefore basic and diluted net income per unit are the same.

2. Recent Accounting Pronouncements

In April 2014, the FASB issued ASU No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This guidance amends the requirements for reporting discontinued operations and requires expanded disclosures for individually significant components of an entity that either have been disposed of or are classified as held for sale, but do not qualify for discontinued operations reporting. Only those disposals of components of an entity that represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. ASU 2014-08 is effective for annual periods, and interim periods within those years, beginning on or after December 15, 2014 and is applied prospectively. Early adoption is permitted, but only for disposals or classifications as held for sale that have not been reported in financial statements previously issued or available for issuance. The update was early adopted by the Partnership as of April 1, 2014 and did not have a material impact on its consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), which amends the existing accounting standards for revenue recognition. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is not permitted. The Partnership is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements-Going Concern (Topic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This guidance provides additional information to guide management's evaluation of whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. The update is effective for annual periods beginning on or after December 15, 2016. The Partnership has evaluated the impact of this standard on its financial statements and determined it will not have a material impact.

3. Acquisitions

Costar Acquisition

On October 14, 2014, the Partnership acquired 100% of the membership interests of Costar Midstream, L.L.C. ("Costar") from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC, in exchange for $265.4 million in cash and 6.9 million of the Partnership's limited partner common units ("Costar Acquisition"). Costar Midstream is an onshore gathering and processing company with its primary gathering, processing, fractionation, and off-spec condensate treating and stabilization assets in East Texas and the Permian basin, with a significant crude oil gathering system project underway in the Bakken oil play.

The Costar Acquisition was accounted for using the acquisition method of accounting and as a result, the aggregate purchase price was allocated to the assets acquired, liabilities assumed and a noncontrolling interest in a Costar subsidiary based on their respective fair values as of the acquisition date. The excess of the aggregate purchase price of the fair values of the assets acquired, liabilities assumed and the noncontrolling interest was classified as goodwill, which is attributable to future prospective customer agreements from the acquisition. Costar has been included in the Partnership's Gathering and Processing Segment from the acquisition date.

The following table summarizes the fair value of consideration transferred to acquire Costar and the preliminary allocation of that amount to the assets acquired, liabilities assumed and the noncontrolling interest based upon their respective fair values as of the acquisition date. Such allocation will be finalized once the Partnership negotiates a final settlement of working capital amounts with the sellers with any resulting adjustment being recorded to goodwill.

| | |
|---|---|
| Fair value of consideration transferred (in thousands): | |
| Cash | $265,383 |
| Limited partner common units | 147,296 |
| Total fair value of consideration | $412,679 |
| Fair Value of assets acquired, liabilities assumed and noncontrolling interest (in thousands): | |
| Working capital | $8,152 |
| Property, plant and equipment: | |
| Processing plants | $48,357 |
| Pipelines | 128,799 |
| Land | 1,244 |
| Buildings | 682 |
| Equipment | 9,827 |
| Construction in progress | 16,146 |
| Total property, plant and equipment | 205,055 |
| Investment in unconsolidated affiliate | 11,884 |
| Intangible assets: | |
| Customer relationships | 53,400 |
| Dedicated acreage | 32,000 |
| Goodwill | 102,407 |
| Noncontrolling interest | (219) |
| | $412,679 |

The fair value of the limited partner common units of $147.3 million differs from the amount determined using the market price of such units on the date of the acquisition as a result of restrictions which require the sellers to hold the units for specified periods of time. The fair value of limited partner units issued in the transaction was determined using an option pricing model and the following key assumptions: i) the closing unit market price on the day of the acquisition, ii) the contractual holding periods, iii) historical unit price volatility for the Partnership and its peers, and iv) a risk-free rate of return.

The fair value of property, plant and equipment was determined using both the cost and market approaches which required significant Level 3 inputs. Key assumptions included i) estimated replacement costs for individual assets or asset groups, ii) estimated remaining useful lives for the acquired assets, and iii) recent market transactions for similar assets. The fair value of intangible assets was determined using the income approach which also required significant Level 3 inputs. Key assumptions included i) estimated throughput volumes, ii) forward market prices for natural gas and NGLS as of the acquisition date, iii) estimated future operating and development cash flows, and iv) discount rates ranging from 11.0% to 16.0%.

The intangible assets acquired relate to existing customer relationships which Costar had at the time of the acquisition, as well as agreements with two producers under which Costar agreed to construct and operate gathering and processing facilities in exchange for the producers' agreements to dedicate certain acreage and related production to those facilities. Working capital includes $11.2 million of accounts receivable, all of which were subsequently collected.

Costar contributed revenue of $19.9 million and operating income of $0.3 million for the period October 14, 2014 through December 31, 2014, attributable to the Partnership's Gathering and Processing segment. Additionally, the

Partnership incurred $0.5 million of transaction costs related to the acquisition which are included in Selling, general and administrative expenses in the consolidated statement of operations for the year ended December 31, 2014. The following unaudited pro forma summary presents consolidated financial information for the Partnership as if the Costar acquisition had occurred on January 1, 2013 (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Revenue | $435,133 | $448,748 |
| Net loss | (101,237) | (30,672) |
| Limited partners' net loss per unit | (6.15) | (3.82) |

These pro forma amounts have been calculated after applying the Partnership’s accounting policies to Costar’s historical results and making adjustments to reflect additional interest expense that would have been incurred and additional depreciation and amortization expense that would have been recognized had the acquisition occurred as of January 1, 2013. The unaudited pro forma adjustments are based on available information and certain assumptions we believe are reasonable.

Lavaca Acquisition

On January 31, 2014, the Partnership acquired approximately 120 miles of high- and low-pressure pipelines and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas from Penn Virginia Corporation (NYSE: PVA) ("PVA") for $104.4 million in cash (the "Lavaca Acquisition"). The Lavaca Acquisition was financed with proceeds from the Partnership's January 2014 equity offering and from the issuance of Series B Units to our General Partner.

The Lavaca Acquisition was accounted for using the acquisitions method of accounting and, as a result, the purchase price was allocated to the assets acquired upon their respective fair values as of the acquisition date. The excess of the purchase price over the fair value of the assets acquired was classified as goodwill.

The following table summarizes the preliminary allocation of the purchase price to the assets acquired based upon their respective fair values as of the acquisition date. Such allocation will be finalized once the Partnership negotiates a final settlement of property, plant and equipment expenditures with the sellers, with any resulting adjustment being recorded to goodwill (in thousands):

| | |
|---|---|
| Property, plant and equipment: | |
| Land | $2 |
| Pipelines | 58,737 |
| Equipment | 753 |
| Total property, plant and equipment | 59,492 |
| Intangible assets | 21,350 |
| Goodwill | 23,567 |
| Total cash consideration | $104,409 |

During the fourth quarter of 2014, errors were identified in the spreadsheets used to determine the preliminary purchase price allocation for the Lavaca Acquisition, which resulted in a $23.6 million overstatement of the previously reported amount allocated to intangible assets with an offsetting understatement of goodwill. These errors also resulted in a $0.5 million overstatement of amortization expense for the first nine months of 2014. The preliminary purchase price allocation as summarized above has been revised to correct these errors. Additionally, an adjustment was recorded during the fourth quarter of 2014 to correct the overstatement of amortization expense which occurred during the first nine months of the year.

The fair value of property, plant and equipment was determined using the cost approach which required significant Level 3 inputs. Key assumptions included i) estimated replacement costs for individual assets or asset groups and ii) estimated remaining useful lives for the acquired assets. The fair value of intangible assets was determined using the income approach which also required significant Level 3 inputs. Key assumptions included i) estimated throughput volumes, ii) future operating and development cash flows, and iii) a discount rate of 10.5%.

The intangible assets acquired relate to a 25-year gas gathering agreement under which PVA will dedicate certain acreage and related production to the acquired facilities.

Lavaca contributed revenue of $16.8 million and net income of $7.6 million for the period from January 31, 2014 through December 31, 2014, attributable to the Partnership's Gathering and Processing segment. The Partnership incurred $0.1 million of transaction costs related to the acquisition, which are included in Selling, general and administrative expenses in the consolidated statement of operations for the year ended December 31, 2014.

Pro forma financial results are not presented as it is impractical to obtain the necessary information. The seller did not operate the acquired assets as a standalone business and, therefore, historical financial information that is consistent with the operations under the current agreement is not available.

Other Acquisitions

Investment in Unconsolidated Affiliate

On August 11, 2014, the Partnership acquired a 66.7% non-operated interest in MPOG, an offshore oil gathering system, for a net purchase price of $12.0 million, which was financed with borrowings from the Partnership's credit facility. Although the Partnership owns a majority interest in MPOG, the ownership structure requires unanimous approval of all owners on decisions impacting the operation of the assets and any changes in ownership structure. Therefore, the Partnership's voting rights are not proportional to its obligation to absorb losses or receive returns. The Partnership accounts for its 66.7% interest using the equity method. The Partnership recorded $0.3 million in earnings from unconsolidated affiliate, and received cash distributions of $2.0 million for the year ended December 31, 2014. The excess of the cash distributions received over the earnings recorded from MPOG is classified as a return of capital within the investing section of our consolidated statement of cash flows.

Williams Pipeline Acquisition

In the first quarter of 2014, the Partnership acquired natural gas pipeline facilities that are contiguous to and connect with our High Point System in offshore Louisiana from Transcontinental Gas Pipe Line Company, LLC ("Transco"), a subsidiary of Williams Partners, LP for $6.5 million  in cash (the "Williams Pipeline Acquisition"). The acquisition was subject to FERC approval of the seller's application to abandon by sale to us the pipeline facilities and to permit the facilities to serve a gathering function, exempt from FERC's jurisdiction. The FERC granted approval of the application during the first quarter of 2014, and the purchase and sale agreement closed on March 14, 2014. The purchase price was allocated to pipelines using the income approach which required certain Level 3 inputs.

Blackwater Terminals Acquisition

On December 17, 2013, the Partnership acquired Blackwater Midstream Holdings LLC ("Blackwater"), a Delaware limited liability company and other related subsidiaries from an affiliate of HPIP. Blackwater operated 1.3 million barrels of storage capacity across four marine terminal sites located in Westwego, Louisiana; Brunswick, Georgia; Harvey, Louisiana; and Salisbury, Maryland.

The Partnership distributed consideration of $63.9 million, of which $27.7 million was accounted for as a cash distribution to the General Partner. The consideration also included 125,500 limited partner units which were accounted for as a non-cash distribution to the General Partner at a fair value of $3.1 million. The fair value of the units issued was determined using level one inputs based upon the Partnership's closing unit price on December 17, 2013.

The remaining consideration was utilized to settle all of the Blackwater's outstanding debt at December 17, 2013.

The acquisition of Blackwater represents a transaction between entities under common control and a change in reporting entity. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period or date of common control. Therefore, net assets received were recorded at their historical book value of $22.7 million as of the date common control was established, which is April 15, 2013.

For the period from April 15, 2013 to December 31, 2013, our Terminals segment contributed $9.8 million of revenue and $0.8 million of net loss attributable to the Partnership's Terminals segment, which are included in the consolidated statement of operations.

High Point System

Effective April 15, 2013, our General Partner contributed the High Point System, consisting of 100% of the limited liability company interests in High Point Gas Transmission, LLC, and High Point Gas Gathering, LLC. The High Point System consists of approximately 700 miles of natural gas and liquids pipeline assets located in southeast Louisiana, in the Plaquemines and St. Bernard parishes, and the shallow water and deep shelf Gulf of Mexico, including the Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound zones. Natural gas is collected at more than 75 receipt points that connect hundreds of wells with an emphasis on oil and liquids-rich reservoirs.

The High Point System, along with $15.0 million in cash, was contributed to us by HPIP in exchange for 5,142,857 Series A Units. Of the cash consideration paid by HPIP, approximately $2.5 million was used to pay certain transaction expenses of HPIP, and the remaining approximately $12.5 million was used to repay borrowings outstanding under the Partnership's former credit facility. The contribution of the High Point System occurred concurrently with HPIP's acquisition of 90% of our General Partner and all of our subordinated units, which resulted in HPIP gaining control of our General Partner and a majority of our outstanding limited partner interests.

The fair value of the Series A Units on April 15, 2013, was $17.50 per unit, or a total of $90.0 million, and was issued by the Partnership in exchange for net cash of approximately $12.5 million and net assets of $61.9 million contributed to the Partnership by our General Partner. The contribution of net assets of the High Point System was accounted for as a transaction between entities under common control whereby the High Point System was recorded at historical book value. As such, the value of the Series A Units in excess of the net assets contributed by our General Partner amounted to $15.6 million and was allocated pro-rata to our General Partner and existing limited partners' interest based on their ownership interests.

The fair value measurement was based on significant inputs not observable in the market and thus represents a Level 3 measurement as defined by ASC 820. Primarily using the income approach, the fair value estimate was based on i) present value of estimated future contracted distributions, ii) an assumed discount rate of 18.0%, and iii) an assumed distribution growth rate of 1.0% in 2014 and thereafter.

The fair value of the additional Series A Units in an amount equal to the cash portion of the distribution was $19.67 per unit, or a total distribution of $13.2 million for the year ended December 31, 2014. Primarily using the market and income approach, the fair value estimate was based on i) present value of estimated future contracted distributions, ii) an option value of $3.32 per unit using a Black-Scholes model, iii) an assumed discount rate of 10.0%, and iv) an assumed distribution growth rate of 1.0% in 2014 and thereafter.

The contribution was treated as a transaction between entities under common control, under which the net assets received are recorded at their historical book value as of date of transfer. The following table presents the carrying value of the identified assets received and liabilities assumed at the acquisition date (in thousands):

| | |
|---|---|
| Cash and cash equivalents | $1,935 |
| Accounts receivable | 3,629 |
| Unbilled revenue | 1,446 |
| Other current assets | 2,049 |
| Property, plant and equipment, net | 82,615 |
| Other assets | 1,000 |
| Accounts payable | (11) |
| Accrued expenses and other current liabilities | (4,077) |
| Current portion of long-term debt | (893) |
| Asset retirement obligation liability | (25,763) |
| Total identifiable net assets | $61,930 |

Subsequent to the contribution, for the year ended December 31, 2013, the High Point System contributed $30.4 million of revenue and $7.2 million of net income attributable to the Partnership's Transmission segment, which are included in the consolidated statement of operations.

Chatom Gathering, Processing and Fractionation Plant

Effective July 1, 2012, we acquired an 87.4% undivided interest in the Chatom system from affiliates of Quantum Resources Management, LLC. The acquisition fair value consideration of $51.4 million includes a credit associated with the cash flow the Chatom system generated between January 1, 2012, and the effective date of July 1, 2012. The consideration paid by the Partnership consisted of cash, which was funded under borrowings under our revolving credit facility.

The Chatom system is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi, and consists of a 25 MMcf/d cryogenic processing plant, a 1,900 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 24 mile gas gathering system. We believe the fractionating services provide flexibility to the Partnership's product and service offerings.

The following table presents the fair value of consideration transferred to acquire the Chatom system and the amounts of identified assets acquired and liabilities assumed at the acquisition date, as well as the fair value of the 12.6% noncontrolling interest in the Chatom system at the acquisition date (in thousands):

| | | |
|---|---|---|
| Cash consideration: | $51,377 | |
| Recognized amounts of identifiable assets acquired and liabilities assumed: | | |
| Unbilled revenue | $4,535 | |
| Property, plant and equipment | 58,279 | |
| Asset retirement cost | 452 | |
| Accounts payable | (399 | ) |
| Accrued gas purchases | (3,631 | ) |
| Asset retirement obligations | (452 | ) |
| Noncontrolling interest | (7,407 | ) |
| Total identifiable net assets: | $51,377 | |

The fair value of the property, plant and equipment and noncontrolling interests were estimated by applying a combination of the market and income approaches. These fair value measurements are based on significant inputs not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. Primarily using the income approach, the fair value estimates are based on i) an assumed cost of capital of 9.25%, ii) an assumed terminal value based on the present value of estimated EBITDA, iii) an inflationary cost increase of 2.5%, iv) forward market prices as of July 2012 for natural gas and crude oil, v) a Federal tax rate of 35% and a state tax rate of 6.5%, and vi) an increase in processed and fractionated volumes in 2013, declining thereafter. Working capital was estimated using net realizable value. Accrued revenue was deemed to be fully collectible at July 1, 2012.

During the fourth quarter of 2013 we offered to purchase the noncontrolling interest in Chatom from all holders of the noncontrolling interest. As of December 31, 2013, 38% of the noncontrolling interest was purchased by us (a 4.8% overall interest), increasing our total ownership to 92.2% and reducing the noncontrolling interest to 7.8%.

Subsequent to the initial 87.4% acquisition, our undivided interest in the Chatom system contributed $25.4 million of revenue and $1.8 million of net income attributable to the Partnership, which are included in the consolidated statement of operations for the year ended December 31, 2012.

Madison Divestiture

On March 31, 2014, the Partnership completed the sale of certain gathering and processing assets in Madison County, Texas. We received $6.1 million in cash proceeds related to the sale. The Partnership recognized a $3.0 million impairment charge related to these assets for the year ended December 31, 2013, which wrote down the assets to a carrying value of $6.1 million as of December 31, 2013.

4. Discontinued Operations

During 2013, the board of directors of our General Partner approved a plan to sell certain non-strategic gathering and processing assets which meet specific criteria, qualifying them as held for sale. During the year ended December 31, 2013, certain gathering and processing assets were written down by $1.8 million to the estimated fair value less cost to sell. These fair value measurements are based on significant inputs not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. Primarily using the income approach, the fair value estimates were based on i) present value of estimated EBITDA, ii) an assumed discount rate of 10%, and iii) a decline in throughput volumes of 2.5% in 2013 and thereafter.

During the second quarter of 2014, the Partnership’s management resolved not to sell a portion of the assets that had previously been reclassified to discontinued operations and assets held for sale in the second quarter of 2013. In accordance with ASC 360, the Partnership reclassified the assets as held and used at the carrying value of the assets before they were classified as held for sale, adjusted for depreciation expense that would have been recorded. The Partnership has reclassified the amounts recorded in discontinued operations related to the assets for all prior periods presented, as well as reclassified the assets to held and used on the comparative December 31, 2013 balance sheet.

The Partnership continues to classify the terminal in Salisbury, Maryland as held for sale as we are continuing negotiations for the sale of those assets, contingent upon the purchaser's completion of funding requirements. The Partnership recognized an additional impairment on these assets of $0.7 million ($0.4 million, net of tax) for the year ended December 31, 2014, due to deteriorating market conditions. The impairment was the result of an analysis of the carrying value of the assets relative to their estimated fair value using a market based approach less costs to sell.

The net book value of the assets and liabilities attributable to the terminal assets are presented separately on the consolidated balance sheet and comprise $0.1 million of Current assets held for sale, $1.2 million of Noncurrent assets held for sale, net, and less than $0.1 million of Current liabilities held for sale as of December 31, 2014.

As a result of the planned divestiture of these non-strategic midstream assets, we have classified these disposal groups as discontinued operations within our consolidated statement of operations. Accordingly, we reclassified and excluded the disposal groups' results of operations from our results of continuing operations and reported the disposal groups' results of operations as Gain (loss) from operations of disposal groups, net of tax in our accompanying consolidated statement of operations for all periods presented. We did not, however, elect to present separately the operating, investing and financing cash flows related to the disposal groups in our accompanying consolidated statement of cash flows as this activity was immaterial for all periods presented. The following table presents the revenue, expense and (loss) gain from operations of disposal groups associated with the assets classified as held for sale for the years ended December 31, 2014, 2013, and 2012 (in thousands, except per unit amounts):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Revenue | $474 | $2,084 | $2,318 |
| Expense | (658) | (2,361) | (2,336) |
| Impairment | (673) | (2,400) | — |
| Loss on sale of assets | (87) | (75) | — |
| Income tax benefit | 333 | 339 | — |
| Gain (loss) from operations of disposal groups, net of tax | $(611) | $(2,413) | $(18) |
| Limited partners' net income (loss) per unit from discontinued operations (basic and diluted) | $(0.04) | $(0.27) | $— |

5. Concentration of Credit Risk and Trade Accounts Receivable

Our primary market areas are located in the United States along the Gulf Coast and in the Southeast. We have a concentration of trade receivable balances due from companies engaged in the production, trading, distribution and marketing of natural gas and NGL products. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. Our customers' historical financial and operating information is analyzed prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. We maintain allowances for potentially uncollectible accounts receivable; however, for the years ended December 31, 2014, 2013 and 2012, no allowances on or significant write-offs of accounts receivable were recorded.

The following table summarizes the percentage of revenue earned from those customers that exceed 10% of the Partnership's consolidated revenue in the consolidated statement of operations for the each of the years presented below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Customer A | 22 % | 28 % | 30 % |
| Customer B | — % | 13 % | — % |
| Customer C | 12 % | 12 % | 13 % |
| Customer D | 10 % | 10 % | 14 % |
| Other | 56 % | 37 % | 43 % |
| Total | 100 % | 100 % | 100 % |

6. Other Current Assets

Other current assets consists of the following (in thousands):

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Prepaid insurance | $4,162 | $3,166 |
| Restricted cash | 6,475 | — |
| Other current assets | 4,865 | 4,331 |
| | $15,502 | $7,497 |

Restricted cash of $6.5 million is a cash-backed letter of credit related to Costar Midstream operations that the Partnership was contractually obligated to maintain after the Costar Acquisition. The Partnership was released of this obligation in January 2015.

7. Derivatives

Commodity Derivatives

To minimize the effect of commodity prices changes and maintain our cash flow and the economics of our development plans, we enter into commodity hedge contracts from time to time. The terms of the contracts depend on various factors, including management's view of future commodity prices, economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price declines while allowing us to participate in some commodity price upside. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the board of directors of our General Partner. Currently, the commodity derivatives are in the form of swaps and collars. As of December 31, 2014, the aggregate notional volume of our commodity derivatives was 0.5 million gallons.

We enter into commodity contracts with multiple counterparties, and in some cases, may be required to post collateral with our counterparties in connection with our derivative positions. As of December 31, 2014, we have not posted collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place that permit us to offset our commodity derivative asset and liability positions with our counterparties .

We did not designate any of our commodity derivatives as hedges for accounting purposes. As a result, our commodity derivatives are accounted for at fair value in our consolidated balance sheets with changes in fair value recognized currently in earnings.

Interest Rate Swap

We entered into an interest rate swap to manage the impact of the interest rate risk associated with our credit facility, effectively converting a portion of the cash flows related to our long-term variable rate debt into fixed rate cash flows. As of December 31, 2014, the notional amount of our interest rate swap was $100.0 million. The interest rate swap was entered into with a single counterparty and we were not required to post collateral. The interest rate swap will expire August 1, 2015.

Weather Derivative

In the second quarter of 2014 and 2013, we entered into weather derivatives to mitigate the impact of potential unfavorable weather to our operations under which we could receive payments totaling up to $10.0 million in the event that a hurricane or hurricanes of certain strength pass through the area as identified in the derivative agreement. The weather derivatives are accounted for using the intrinsic value method, under which the fair value of the contract was zero and any amounts received are recognized as gains during the period received. The weather derivatives were entered into with a single counterparty and we were not required to post collateral.

We paid premiums of $1.0 million and $1.1 million in 2014 and 2013, respectively, which are recorded as current Risk management assets on the consolidated balance sheet and are amortized to Direct operating expenses on a straight-line basis over the term of the contract of 1 year. Unamortized amounts associated with weather derivatives were approximately $0.4 million and $0.5 million as of December 31, 2014 and 2013, respectively.

As of December 31, 2014 and 2013, the value associated with our commodity derivatives, interest rate swap and weather derivative were recorded in our consolidated balance sheets, under the captions as follows (in thousands):

| | Gross Risk Management Assets | | Gross Risk Management Liabilities | | Net Risk Management Assets (Liabilities) | |
|---|---|---|---|---|---|---|
| Balance Sheet Classification | December 31, 2014 | December 31, 2013 | December 31, 2014 | December 31, 2013 | December 31, 2014 | December 31, 2013 |
| Current | $688 | $473 | $— | $— | $688 | $473 |
| Noncurrent | — | — | — | — | — | — |
| Total assets | $688 | $473 | $— | $— | $688 | $473 |
| | | | | | | |
| Current | $— | $27 | $(215) | $(450) | $(215) | $(423) |
| Noncurrent | — | — | — | (101) | — | (101) |
| Total liabilities | $— | $27 | $(215) | $(551) | $(215) | $(524) |

For the years ended December 31, 2014, 2013 and 2012, the realized and unrealized gains (losses) associated with our commodity, interest rate and weather derivative instruments were recorded in our consolidated statements of operations, under the captions as follows (in thousands):

| | Realized | Unrealized |
|---|---|---|
| 2014 | | |
| Gain (loss) on commodity derivatives, net | $735 | $356 |
| Interest expense | (433) | 239 |
| Direct operating expenses | (1,035) | — |
| Total | $(733) | $595 |
| 2013 | | |
| Gain (loss) on commodity derivatives, net | $1,069 | $(1,041) |
| Interest expense | (207) | (454) |
| Direct operating expenses | (662) | — |
| Total | $200 | $(1,495) |
| 2012 | | |
| Gain (loss) on commodity derivatives, net | $2,408 | $992 |
| Total | $2,408 | $992 |

8. Fair Value Measurement

We believe the carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

The recorded value of the amounts outstanding under the credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates and the short-term nature of borrowings and repayments under the credit facility.

The fair value of all derivatives instruments is estimated using a market valuation methodology based upon forward commodity price curves, volatility curves as well as other relevant economic measures, if necessary. Discount factors may be utilized to extrapolate a forecast of future cash flows associated with long dated transactions or illiquid market points. The inputs are obtained from independent pricing services, and we have made no adjustments to the obtained prices.

We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivatives contracts held. We will recognize transfers between levels at the end of the reporting period for which the transfer has occurred. There were no such transfers for the years ended December 31, 2014 and 2013.

Fair Value of Financial Instruments

The following table sets forth by level within the fair value hierarchy, our commodity derivative instruments and interest rate swap, included as part of Risk management assets and Risk management liabilities within the consolidated balance sheet, that were measured at fair value on a recurring basis as of December 31, 2014 and 2013 (in thousands):

| | Carrying Amount | Estimated Fair Value of the Asset (Liability) Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|
| Commodity derivative instruments, net | | | | | |
| December 31, 2014 | $286 | $— | $286 | $— | $286 |
| December 31, 2013 | (70) | — | (70) | — | (70) |
| Interest rate swap | | | | | |
| December 31, 2014 | $(215) | $— | $(215) | $— | $(215) |
| December 31, 2013 | (454) | — | (454) | — | (454) |

The unamortized portion of the premium paid to enter the weather derivative described in Note 7 "Derivatives," is included within Risk management assets on the consolidated balance sheet but is not included in the above table as it is recorded at amortized cost, not fair value.

9. Property, Plant and Equipment, Net

Property, plant and equipment, net, as of December 31, 2014 and 2013, were as follows (in thousands):

| | Useful Life (in years) | December 31, 2014 | December 31, 2013 |
|---|---|---|---|
| Land | N/A | $5,282 | $6,015 |
| Construction in progress | N/A | 77,551 | 6,443 |
| Base gas | N/A | 1,108 | 1,108 |
| Buildings and improvements | 4 to 40 | 6,905 | 5,109 |
| Processing and treating plants | 8 to 40 | 80,141 | 97,106 |
| Pipelines | 5 to 40 | 452,180 | 239,865 |
| Compressors | 4 to 20 | 24,227 | 11,955 |
| Dock | 20 to 40 | 8,072 | 7,942 |
| Tanks, truck rack and piping | 20 to 40 | 30,079 | 22,432 |
| Equipment | 8 to 20 | 8,952 | 6,294 |
| Computer software | 5 | 3,520 | 3,531 |
| Total property, plant and equipment | | 698,017 | 407,800 |
| Accumulated depreciation | | (115,835) | (95,099) |
| Property, plant and equipment, net | | $582,182 | $312,701 |

Of the gross property, plant and equipment balances at December 31, 2014 and 2013, $101.9 million and $100.5 million, respectively, were related to AlaTenn, Midla and High Point Gas Transmission, our FERC regulated interstate and intrastate assets.

Capitalized interest was $0.8 million and $0.2 million for the years ended December 31, 2014 and 2013, respectively.

Depreciation expense was $23.9 million and $25.9 million for the years ended December 31, 2014 and 2013, respectively.

Asset Impairments

2014 Impairments

During the fourth quarter of 2014, management noted the declining commodity markets and related impact on producers and shippers to whom we provide gathering and processing services. The decline in the market price of crude oil has led to a corresponding decrease in oil and natural gas production and is impacting the volume of natural and NGLs we gather and process on certain assets. As a result, an asset impairment charge of $99.9 million was recorded in the three months ended December 31, 2014. These fair value measurements are based on significant inputs not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. Primarily using the income approach, the fair value estimates are based on i) present value of estimated EBITDA, ii) an assumed discount rate of 9.5%, and iii) the expected remaining useful life of the asset or asset group.

The Partnership continues to classify the terminal in Salisbury, Maryland as held for sale as we are continuing negotiations for the sale of those assets, contingent upon the purchaser's completion of funding requirements. The Partnership recognized an additional impairment on these assets of $0.7 million ($0.4 million, net of tax) for the year ended December 31, 2014, due to deteriorating market conditions. The impairment was the result of an analysis of the carrying value of the assets relative to their estimated fair value using a market based approach less costs to sell.

2013 Impairments

During 2013, management determined to change its commercial approach towards certain non-strategic gathering and processing assets. As a result, an asset impairment charge of $15.2 million was recorded in the three months ended June 30, 2013. These fair value measurements are based on significant inputs not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. Primarily using the income approach, the fair value estimates are based on i) present value of estimated EBITDA, ii) an assumed discount rate of 10%, and iii) a decline in throughput volumes of 2.5% in 2013 and thereafter.

During 2013, the board of directors of our General Partner approved a plan to sell certain non-strategic gathering and processing assets which meet specific criteria, qualifying them as held for sale. As a result, certain gathering and processing assets were written down by $1.8 million to the estimated fair value less cost to sell. As part of the Blackwater Acquisition, we acquired long-lived terminal assets classified as held for sale. As of December 31, 2013, certain long-lived terminal assets were written down by $0.6 million to the estimated fair value less cost to sell. See Note 4 "Discontinued Operations."

During the first quarter of 2014, the board of directors of our General Partner gave approval to the management team to pursue the sale of certain gathering and processing assets for an amount less than the carrying value of the assets. As a result, these gathering and processing assets were written down by $3.0 million in the fourth quarter of 2013.

Insurance proceeds

Involuntary conversions result from the loss of an asset because of some unforeseen event (e.g., destruction due to hurricanes). Some of these events are insurable, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. During the year ended December 31, 2013, we collected $1.1 million of nonrefundable cash proceeds from our insurance carrier. During the first quarter of 2013, $0.5 million of nonrefundable cash proceeds were recognized as an offset to property, plant and equipment write-downs of $0.1 million and presented as $0.4 million under the caption Gain (loss) on involuntary conversion of property, plant and equipment. During the second quarter of 2013, $0.6 million of nonrefundable cash proceeds were associated with business interruption insurance and recorded to Revenue in the consolidated statement of operations.

10. Goodwill and Intangible Assets, Net

The carrying value of goodwill as of December 31, 2014 and 2013, was $142.2 million and $16.4 million, respectively. Goodwill as of December 31, 2014 consisted of $125.9 million and $16.3 million related to our Gathering and Processing and Terminal Segments, respectively. Goodwill as of December 31, 2013 related entirely to the Terminals Segment.

The goodwill associated with our Gathering and Processing segment relates to the Costar and Lavaca Acquisitions and primarily represent strategic developmental locations to grow the business within the segment. The goodwill associated with our Terminal Segment was contributed to the Partnership as part of the Blackwater Acquisition. Goodwill was recorded as a result of the excess of the investment by an affiliate of HPIP in Blackwater over the fair market value of the identifiable net assets and customer contracts acquired.

Intangible assets, net, consists of customer contracts, relationships and dedicated acreage agreements identified as part of the Costar Acquisition, Lavaca Acquisition and Blackwater Acquisition. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging from 5 months to thirty years. Intangible assets, net, consist of the following (in thousands):

| | December 31, 2014 | 2013 |
|---|---|---|
| Gross carrying amount: | | |
| Customer contracts | $12,101 | $12,101 |
| Customer relationships | 53,400 | — |
| Dedicated acreage | 53,350 | — |
| | $118,851 | $12,101 |
| Accumulated amortization: | | |
| Customer contracts | $(11,110) | $(8,419) |
| Customer relationships | (553) | — |
| Dedicated acreage | (882) | — |
| | $(12,545) | $(8,419) |
| Net carrying amount: | | |
| Customer contracts | $991 | $3,682 |
| Customer relationships | 52,847 | — |
| Dedicated acreage | 52,468 | — |
| | $106,306 | $3,682 |

For the years ended December 31, 2014 and 2013, amortization expense on our intangible assets totaled $4.1 million and $3.7 million, respectively. Estimated amortization expense for each of the next five fiscal years (2015 – 2019) is approximately $5.3 million, $4.3 million, $4.3 million, $4.3 million and $4.3 million, respectively.

11. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities were as follows (in thousands):

| | December 31, 2014 | 2013 |
|---|---|---|
| Accrued capital expenditures | $17,134 | $2,562 |
| Accrued expenses | 7,036 | 5,412 |
| Gas imbalances payable | 1,069 | 4,305 |
| Other | 549 | 2,779 |
| | $25,788 | $15,058 |

12. Asset Retirement Obligations

The following table is a reconciliation of the asset retirement obligations (in thousands):

| | Year Ended December 31, 2014 | 2013 |
|---|---|---|
| Beginning asset retirement obligation | $34,636 | $8,319 |
| Liabilities assumed | 248 | 25,763 |
| Expenditures | (1,030) | — |
| Accretion expense | 791 | 554 |
| Ending asset retirement obligation | $34,645 | $34,636 |

We are required to establish security against any potential secondary obligations relating to the abandonment of the certain transmission assets that may be imposed on the previous owner by applicable regulatory authorities. As such, we have a restricted cash account that is established, held and maintained by a third party that amounted to $5.0 million and $3.0 million as of December 31, 2014 and 2013, respectively, and is presented in Other assets, net in our consolidated balance sheets.

13. Debt Obligations

Our outstanding borrowings under the credit facility were (in thousands):

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Revolving credit facility | $372,950 | $130,735 |
| Other debt | 2,908 | 2,048 |
| Total debt | 375,858 | 132,783 |
| Less: current portion | 2,908 | 2,048 |
| Long-term debt | $372,950 | $130,735 |

On September 5, 2014, the Partnership entered into an amended and restated credit agreement (the "Credit Agreement"), which provides for a maximum borrowing equal to $500.0 million, with the ability to further increase the borrowing capacity subject to lender approval. We can elect to have loans under our credit facility bear interest either at a Eurodollar-based rate plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (a) the Federal Funds Rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its "prime rate," or (c) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a maximum commitment fee of 0.50% per annum on the undrawn portion of the revolving loan.

Our obligations under the credit facility are secured by a first mortgage in favor of the lenders in our real property. Advances made under the Credit Agreement are guaranteed on a senior unsecured basis by certain of our subsidiaries (the "Guarantors"). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the new credit facility include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full on the maturity date, September 5, 2019.

The Credit Agreement contains certain financial covenants, including the requirement that our indebtedness not exceed 4.75 times adjusted consolidated EBITDA (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant is increased to 5.25 times adjusted Consolidated EBITDA) and a minimum interest coverage ratio test (not less than 2.50). The Credit Agreement also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

For the years ended December 31, 2014, 2013 and 2012, the weighted average interest rate on borrowings under our credit facilities was approximately 3.80%, 4.53%, and 4.09%, respectively.

As of December 31, 2014 our consolidated total leverage was 4.44 and our interest coverage ratio was 13.44, which was in compliance with the consolidated total leverage ratio and interest coverage ratio tests in accordance with the financial covenants required in our Credit Agreement. At December 31, 2014 and 2013, letters of credit outstanding under the credit facility were $1.6 million and $4.8 million, respectively. As of December 31, 2014, we had approximately $373.0 million of outstanding borrowings under our $500.0 million credit facility.

Other debt

Other debt represents insurance premium financing in the original amount of $3.3 million bearing interest at 3.95% per annum, which is repayable in equal monthly installments of approximately $0.4 million through the third quarter of 2015.

In connection with our credit facility, we have incurred $10.4 million in cumulative debt issuance costs through December 31, 2014, which are being amortized on a straight-line basis over the term of the credit facility. In connection with the amendment and restatement of our Credit Agreement, discussed above, the Partnership recognized $0.7 million in extinguishment costs during the quarter ended September 30, 2014, which is included in Other expense in our consolidated statement of operations.

14. Partners' Capital

Our capital accounts are comprised of approximately 1.3% general partner interest and 98.7% limited partner interests as of December 31, 2014. Our limited partners have limited rights of ownership as provided for under our partnership agreement and the right to participate in our distributions. Our General Partner manages our operations and participates in our distributions, including certain incentive distributions rights ("IDRs") that are non-voting limited partner interests held by our General Partner.

Series B Units

Effective January 31, 2014, the Partnership created and issued to its General Partner 1,168,225 Series B Units in exchange for cash. The Series B Units participate in distributions of the Partnership along with common units, with such distributions being made in cash distributions or with paid-in-kind Series B Units at the election of the Partnership. The Series B Units are entitled to vote along with common unitholders and such units will automatically convert to common units two years after the issuance date. Proceeds from the issuance of the Series B Units were used to partially fund the Lavaca Acquisition.

During 2014, the Partnership elected to pay the Series B distributions using paid-in-kind Series B Units. The number of paid-in-kind Series B Units is determined by the quotient of: i) the number of Series B Units outstanding at the record date multiplied by the distribution amount declared to common unit holders ("Series B Unit Distribution Amount"), and ii) the Series B Unit Distribution Amount divided by the original issue price of the Series B Units. The Partnership records the paid-in-kind Series B Units at fair value at the time of issuance. The fair value measurement uses our unit price as a significant input in the determination of the fair value and thus represents a Level 2 measurement as defined by ASC 820. For the year ended December 31, 2014, the Partnership issued 86,461 of paid-in-kind Series B Units with a fair value of $2.2 million.

Series A Convertible Preferred Units

On April 15, 2013, the Partnership, our General Partner and AIM Midstream Holdings entered into agreements with HPIP, pursuant to which HPIP i) acquired 90% of our General Partner and all of our subordinated units from AIM Midstream Holdings and ii) contributed certain midstream assets and $15.0 million in cash to us in exchange for 5,142,857 Series A Units issued by the Partnership. Of the cash consideration paid by HPIP, approximately $2.5 million was used to pay certain transaction expenses of HPIP, and the remaining approximately $12.5 million was used to repay borrowings outstanding under the Partnership's former credit facility. As a result of these transactions, which were also consummated on April 15, 2013, HPIP acquired both control of our General Partner and a majority of our outstanding limited partnership interests. On April 15, 2013, our General Partner entered into the Third Amended & Restated Agreement of Limited Partnership (the "Amended Partnership Agreement") of the Partnership providing for the creation and designation of the rights, preferences, terms and conditions of the Series A Units.

The Series A Units receive distributions prior to distributions to Partnership common unitholders. Through October 1, 2014, the distributions to the Series A Unitholders were equal to $0.25 in cash per unit and additional Series A Units in an amount equal to the cash portion of the distribution. Subsequent to that date, the distribution to each Series A Unit is the greater of the distribution to be made on a per unit basis to common unitholders or approximately $0.4125 per unit. The Series A Units may be converted into common units on a one-to-one basis, subject to customary anti-dilutive adjustments, at the option of the unitholders on or any time after January 1, 2014.

Upon any liquidation and winding up of the Partnership or the sale of substantially all of the assets of the Partnership, the holders of Series A Units generally will be entitled to receive, in preference to the holders of any of the Partnership's other securities, an amount equal to the sum of $17.50 multiplied by the number of Series A Units owned by such holders, plus all accrued but unpaid distributions on such Series A Units.

Prior to the consummation of any recapitalization, reorganization, consolidation, merger, spin-off or other business combination in which the holders of common units are to receive securities, cash or other assets (a "Partnership

Event"), we are obligated to make an irrevocable written offer, subject to consummation of the Partnership Event, to each holder of Series A Units to redeem all (but not less than all) of such holder's Series A Units for a price per Series A Unit payable in cash equal to the greater of:

- the sum of $17.50 and all accrued and accumulated but unpaid distributions for each Series A Unit; or
- an amount equal to the product of:

i) the number of common units into which each Series A Unit is convertible; and
ii) the sum of:
(A) the cash consideration per common unit to be paid to the holders of common units pursuant to the Partnership Event, plus
(B) the fair market value per common unit of the securities or other assets to be distributed to the holders of the common units pursuant to the Partnership Event.

Upon receipt of such a redemption offer from us, each holder of Series A Units may elect to receive such cash amount or a preferred security issued by the person surviving or resulting from such Partnership Event and containing provisions substantially equivalent to the provisions set forth in the Amended Partnership Agreement with respect to the Series A Units without material abridgement.
Except as provided in the Amended Partnership Agreement, the Series A Units have voting rights that are identical to the voting rights of the common units and will vote with the common units as a single class, with each Series A Unit entitled to one vote for each common unit into which such Series A Unit is convertible.

As conversion is at the option of the holder and redemption is contingent upon a future event which is outside the control of the Partnership, the Series A Units have been classified as mezzanine equity in the consolidated balance sheets.

The Partnership executed an amendment (the "Amendment") to the Partnership agreement related to its outstanding Series A convertible preferred units ("Series A Units") which became effective July 24, 2014. As a result of the Amendment, distributions on Series A Units will be made with paid-in-kind Series A Units, cash or a combination thereof, at the discretion of the Board of Directors, which began with the distribution for the three months ended June 30, 2014 and will continue through the distribution for the quarter ended March 31, 2015. Prior to the Amendment, the Partnership was required to pay distributions on the Series A Units with a combination of paid-in-kind units and cash. At December 31, 2014, we have accrued $3.2 million for the paid-in-kind Series A Units.

Equity Restructuring

Effective August 9, 2013, we executed an equity restructuring agreement ("Equity Restructuring") with our General Partner and HPIP. As part of the Equity Restructuring, the Partnership's 4,526,066 subordinated units and previous incentive distribution rights (the "former IDRs," all of which were owned by our General Partner, which is controlled by HPIP) were combined into and restructured as a new class of incentive distribution rights (the "new IDRs"). Upon the issuance of the new IDRs, the subordinated units and former IDRs were canceled. The new IDRs were allocated 85.02% to HPIP and 14.98% to our General Partner. The new IDRs entitle the holders of our incentive distribution rights to receive 48% of any quarterly cash distributions from available cash after the Partnership's common unitholders have received the full minimum quarterly distribution ($0.4125 per unit) for each quarter plus any arrearages from prior quarters. On February 5, 2014, further amendments were made as a result of a settlement such that:

- HPIP and AIM Midstream Holdings amended the LLC Amendment to, among other things, amend the Sharing Percentages (as defined therein) such that HPIP's sharing percentage thereafter is 95% and AIM Midstream Holdings's Sharing Percentage is 5%;

- HPIP transferred all of the 85.02% of our outstanding new IDRs held by HPIP to our General Partner such that our General Partner owns 100% of the outstanding new IDRs; and

- we issued to AIM Midstream Holdings a warrant to purchase up to 300,000 common units of the Partnership at an exercise price of $0.01 per common unit (the "Warrant"), which Warrant, among other terms, i) is exercisable at any time on or after February 8, 2014 until the tenth anniversary of February 5, 2014, ii) contains cashless exercise provisions and iii) contains customary anti-dilution and other protections. The Warrant was exercised on February 21, 2014.

Equity Offerings

On October 14, 2014, the Partnership acquired Costar Midstream from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC which was funded, in part, with 6.9 million of limited partner common units issued directly to Energy Spectrum and Costar Midstream Energy LLC, which are subject to customary lock-up provisions.

On July 14, 2014, the Partnership entered into a common unit purchase agreement with certain institutional investors, which was subsequently amended on August 15, 2014, to provide for the sale of 4,622,352 common units representing limited partner interests in the Partnership in a private placement at a price of $25.8075 per common unit (reflecting an adjustment for the Partnership's second quarter distribution of $0.4625 per unit), for cash consideration of $119.3 million.

On January 29, 2014, the Partnership and certain of its affiliates entered into an underwriting agreement (the "Underwriting Agreement") with Barclays Capital Inc. and UBS Securities LLC (the "Underwriters"), providing for the issuance and sale by the Partnership, and the purchase by the Underwriter, of 3,400,000 common units representing limited partner interests in the Partnership at a price to the public of $26.75 per common unit. The Partnership used the net proceeds of $86.9 million to fund a portion of the Lavaca Acquisition.

On December 11, 2013, the Partnership and certain of its affiliates entered into an underwriting agreement (the "Underwriting Agreement") with Barclays Capital Inc. (the "Underwriter"), providing for the issuance and sale by the Partnership, and the purchase by the Underwriter, of 2,568,712 common units representing limited partner interests in the Partnership at a price to the public of $22.47 per common unit. The Partnership used the net proceeds of $54.9 million to fund a portion of the purchase price for the Blackwater Acquisition.

General Partner Units

In connection with the equity offerings discussed above, we received proceeds of $5.7 million from our General Partner as consideration for 206,810 additional notional general partner units.

Outstanding Units

The numbers of units outstanding were as follows (in thousands):

| | December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Series A convertible preferred units | 5,745 | 5,279 | — |
| Series B convertible units | 1,255 | — | — |
| Limited Partner common units | 22,670 | 7,414 | 4,639 |
| Limited Partner subordinated units | — | — | 4,526 |
| General Partner units | 392 | 185 | 185 |

Distributions

We made cash distributions as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Series A convertible preferred units | 2,658 | 2,375 | — |
| Limited Partner common units | 22,656 | 8,207 | 7,919 |
| Limited Partner subordinated units | — | 5,073 | 7,830 |
| General Partner units | 333 | 284 | 321 |
| General Partners' incentive distribution rights | 2,362 | 181 | — |
| | $28,009 | $16,120 | $16,070 |

At December 31, 2014, we have accrued $3.2 million for the paid-in-kind Series A Units. The distributions will be made in the first quarter of 2015. During the year ended December 31, 2014, we issued 555 thousand Series A PIK Units and 86 thousand Series B PIK Units.

15. Net Income (Loss) per Limited Partner Unit

Net income (loss) is allocated to the General Partner and the limited partners in accordance with their respective ownership percentages, after giving effect to distributions on Series A preferred convertible units, declared distributions on the Series B Units, limited partner and to the General Partner units, including IDRs. Unvested unit-based payment awards that contain non-forfeitable rights to distributions (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted net income per limited partner unit. Basic and diluted net income (loss) per limited partner unit is calculated by dividing limited partners' interest in net income (loss) by the weighted average number of outstanding limited partner units during the period. We determined basic and diluted net income (loss) per limited partner unit as follows, (in thousands, except per unit amounts):

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| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Net income (loss) from continuing operations | $(97,195) | $(30,993) | $(6,234) |
| Net income (loss) attributable to noncontrolling interests | 214 | 633 | 256 |
| Net income (loss) from continuing operations attributable to the Partnership | (97,409) | (31,626) | (6,490) |
| Less: | | | |
| Distributions on Series A preferred units | 14,492 | 24,117 | — |
| Declared distributions on Series B Units | 2,220 | — | — |
| General partner's distributions | 2,694 | 464 | 322 |
| General partner's share in undistributed loss | (1,820) | (1,708) | (458) |
| Blackwater net loss from continuing operations | — | (716) | — |
| Net income (loss) from continuing operations available to limited Partners | (114,995) | (53,783) | (6,354) |
| Net income (loss) from discontinued operations available to Limited Partners | (603) | (2,051) | (18) |
| Net income (loss) available to Limited Partners | $(115,598) | $(55,834) | $(6,372) |
| | | | |
| Weighted average number of units used in computation of Limited Partners' net income (loss) per unit (basic and diluted) | 13,472 | 7,525 | 9,113 |
| | | | |
| Limited Partners' net income (loss) from continuing operations per unit (basic and diluted) | $(8.54) | $(7.15) | $(0.70) |
| Limited Partners' net income (loss) from discontinued operations per unit (basic and diluted) | (0.04) | (0.27) | — |
| Limited Partners' net income (loss) per unit (basic and diluted) | $(8.58) | $(7.42) | $(0.70) |

## 16. Long-Term Incentive Plan

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. On November 2, 2009, the board of directors of our General Partner adopted a long-term incentive plan for its employees, consultants and directors who perform services for it or its affiliates. On May 25, 2010, the board of directors of our General Partner adopted an amended and restated long-term incentive plan. On July 11, 2012, the board of directors of our General Partner adopted a second amended and restated long-term incentive plan ("LTIP") that effectively increased available awards by 871,750 units. At December 31, 2014, 2013 and 2012, there were 688,976, 855,089 and 920,193 units, respectively, available for future grant under the LTIP.

Ownership in the awards is subject to forfeiture until the vesting date. The LTIP is administered by the board of directors of our General Partner. The board of directors of our General Partner, at its discretion, may elect to settle such vested phantom units with a number of units equivalent to the fair market value at the date of vesting in lieu of cash. Although our General Partner has the option to settle in cash upon the vesting of phantom units, our General Partner has not historically settled these awards in cash. Although other types of awards are contemplated under the LTIP, the only currently outstanding awards are phantom units without distribution equivalent rights ("DERs").

Generally, grants issued under the LTIP vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment.

The following table summarizes our unit-based awards for each of the periods indicated, in units:

| | Year Ended December 31, 2014 | |
|---|---|---|
| | Shares | Weighted-Average Exercise Price |
| Outstanding at beginning of period | 75,529 | 17.62 |
| Granted | 188,946 | 20.80 |
| Forfeited | (12,009) | 18.28 |
| Vested | (51,334) | 20.89 |
| Outstanding at end of period | 201,132 | 19.73 |

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our units at the grant date. Compensation costs related to these awards for the years ended December 31, 2014, 2013, and 2012 was $1.5 million, $2.1 million and $1.8 million, respectively, and are classified as Equity compensation expense in the consolidated statement of operations and the equity based compensation in partners' capital on the consolidated balance sheet.

The total fair value of vesting units at the time of vesting was $1.4 million, $2.2 million, and $1.9 million for the years ended December 31, 2014, 2013, and 2012, respectively.

The total compensation cost related to unvested awards not yet recognized at December 31, 2014, 2013, and 2012 was $3.1 million, $0.9 million, and $1.4 million, respectively, and the weighted average period over which this cost is expected to be recognized as of December 31, 2014, is approximately 3 years.

## 17. Postretirement Benefits

We sponsor a contributory postretirement plan that provides medical, dental and life insurance benefits for qualifying U.S. retired employees (referred to as the "OPEB Plan").

The tables below detail the changes in the benefit obligation, the fair value of the plan assets and the funded status of the OPEB Plan using the accrual method (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Change in benefit obligation | | |
| Benefit obligation, beginning of period | $532 | $472 |
| Service cost | 2 | 5 |
| Interest cost | 24 | 15 |
| Actuarial (gain) loss | 122 | (29) |
| Plan amendments | — | 126 |
| Benefits paid | (25) | (57) |
| Benefit obligation, end of period | $655 | $532 |
| Change in plan assets | | |
| Fair value of plan assets, beginning of period | $1,528 | $1,552 |
| Actual return on plan assets | 104 | (53) |
| Employer's contributions | 90 | 90 |
| Benefits paid | (38) | (61) |
| Fair value of plan assets, end of period | $1,684 | $1,528 |
| Funded status | | |
| Funded status | $1,029 | $996 |

The funded status of the OPEB plan is included in Other assets in the consolidated balance sheets.

The amounts included in accumulated other comprehensive income (loss) at December 31, 2014, 2013 and 2012 that have not been recognized as components of net periodic benefit expenses are $0.0 million, $(0.1) million, and $(0.1) million, respectively, which relate to net (gains) losses.

Components of Net Periodic Benefit Cost and Other amounts Recognized in Other Comprehensive Income (in thousands):

| | Year Ended December 31, | | |
| --- | --- | --- | --- |
| | 2014 | 2013 | 2012 |
| Net Periodic Benefit Cost | | | |
| Service cost | $2 | $5 | $4 |
| Interest cost | 24 | 15 | 18 |
| Expected return on plan assets | (70) | (70) | (67) |
| Amortization of prior service cost | 4 | — | — |
| Amortization of net (gain) loss | (5) | (23) | (43) |
| Net periodic benefit cost | $(45) | $(73) | $(88) |
| Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income | | | |
| Net (gain) loss | $102 | $247 | $64 |
| Total recognized in other comprehensive income | 102 | 247 | 64 |
| Total recognized in net periodic benefit cost and other comprehensive income | $57 | $174 | $(24) |

The estimated net gain that will be amortized from accumulated other comprehensive income (loss) into net periodic benefit cost over the next fiscal year is less than $0.1 million.

Economic assumptions

The assumptions made in measurement of the projected benefit obligations or assets of the OPEB Plan were as follows:

| | Year Ended December 31, | |
| --- | --- | --- |
| | 2014 | 2013 |
| Discount rate | 3.73% | 4.57% |
| Expected return on plan assets | 2.50% | 4.50% |
| Health care trend rate | 3.00% | 4.50% |

A one percent change in the assumed health care trend rate would result in a change of less than $0.1 million in the postretirement benefit obligations.

The above table reflects the expected long-term rates of return on assets of the OPEB Plan on a weighted-average basis. The overall expected rates of return are based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations. We believe this rate approximates the return we will achieve over the long-term on the assets of our plans. Historically, we have used a discount rate that corresponds to one or more high quality corporate bond indices as an estimate of our expected long-term rate of return on plan assets for our OPEB Plan assets. For 2014, 2013 and 2012 we selected the discount rate using the Citigroup Pension Discount Curve, or CPDC. The CPDC spot rates represent the equivalent yield on high-quality, zero-coupon bonds for specific maturities. These rates are used to develop a single, equivalent discount rate based on the OPEB Plan's expected future cash flows.

Expected future benefit payments

The following table presents the benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five years thereafter by the OPEB Plan (in thousands):

| | |
|---|---|
| For the year ending | |
| 2015 | $33.0 |
| 2016 | 32.0 |
| 2017 | 32.0 |
| 2018 | 32.0 |
| 2019 | 31.0 |
| Five years thereafter | 194.0 |

The expected future benefit payments are based upon the same assumptions used to measure the projected benefit obligations of the OPEB Plan, including benefits associated with future employee service.

Future contributions to the Plans

We expect to make contributions of $0.1 million to the OPEB Plan for the year ending December 31, 2015.

Plan assets

The weighted average asset allocation of our OPEB Plan at the measurement date by asset category, which are all classified as Level 1 investments, are as follows:

| | December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| Fixed income (a) | 70.0 | % | 70.1 | % | 72.2 | % |
| Other (b) | 30.0 | % | 29.9 | % | 27.8 | % |
| Total | 100.0 | % | 100.0 | % | 100.0 | % |

(a) United States government securities, municipal corporate bonds and notes and asset backed securities
(b) Cash and securities with maturities of one year or less

18. Income Taxes

The Partnership is not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. The State of Texas imposes a margin tax that is assessed at 0.95%, 0.975% and 1% of taxable margin apportioned to Texas for each of the three years in the period ended December 31, 2014, respectively. Effective December 17, 2013, we acquired Blackwater Midstream Holdings, LLC, an entity that owns a taxable C Corporation consolidated return group.

For its taxable operations, the Partnership follows the provisions of ASC 740 "Accounting For Income Taxes," which provides for recognition of deferred tax assets and liabilities for deductible temporary timing differences, net operating loss, statutory depletion and tax credit carryforwards, net of a valuation allowance for any deferred tax asset which more likely than not, will not be realized in the Partnership's tax return. An analysis of the Partnership's deferred taxes is as follows (in thousands):

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| Deferred tax assets: | | |
| Net operating loss carryforwards | $4,173 | $5,455 |
| Other | 213 | 182 |
| Total deferred tax assets | 4,386 | 5,637 |

| | | |
|---|---|---|
| Deferred tax liabilities: | | |
| Property, plant and equipment | 9,112 | 9,022 |
| Intangible assets | 387 | 1,364 |
| Total deferred tax liabilities | 9,499 | 10,386 |
| Deferred income tax liability, net | $ (5,113 ) | $ (4,749 ) |

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These amounts reflect the classification and presentation that is reported for each tax jurisdiction in which we operate.

Net deferred income tax assets and liabilities consist of (in thousands):

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| Current deferred tax asset | $3,086 | $— |
| Deferred tax liability, net | (8,199) | (4,749) |
| | $(5,113) | $(4,749) |

As of December 31, 2014, we had approximately $10.7 million of operating loss carryforwards which begin to expire in 2028. Some of our net operating losses may be limited by section 382 of the Internal Revenue Code due to the change in control that occurred in December 2013 and another change in control that occurred in October 2012.

The preparation of our income tax returns requires the use of management's estimates and interpretations which may be subjected to review by the respective taxing authorities and may result in an assessment of additional taxes, penalties and interest. We will account for interest and penalties relating to uncertain tax provisions in the current period statement of operations, as necessary. Tax years 2009 through 2013 remain subject to examination by various federal and state tax jurisdictions, as applicable. During the third quarter of 2014, the Internal Revenue Service commenced an audit of the Partnership's 2012 U.S. federal partnership tax return which remains open to examination.

We must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also on the past administrative practices and precedents of the taxing authority. As of December 31, 2014, we have not recognized tax benefits from uncertain tax positions.

The provision for income taxes is attributable to the activities of the taxable C-Corporation consolidated return group and taxable margin apportioned to Texas. The details of the provision for taxes on income for the year ended December 31, 2014, are as follows (in thousands):

| | Year Ended December 31, 2014 | 2013 |
|---|---|---|
| Net loss before income tax benefit (expense) | $(96,638) | $(31,488) |
| US Federal statutory tax rate | 34% | 34% |
| Federal income tax benefit at statutory rate | 32,857 | 10,706 |
| Reconciling items: | | |
| Partnership loss not subject to income tax | (33,216) | (10,296) |
| Income not subject to corporate-level tax | — | 222 |
| State and local tax benefit (expense) | (159) | 71 |
| Adjustments related to prior years | (37) | (175) |
| Other | (2) | (33) |
| Income tax benefit (expense) | $(557) | $495 |

The income tax provision related to continuing operations consist of the following (in thousands):

| | Year Ended December 31, 2014 | 2013 |
|---|---|---|
| Current income tax benefit (expense) | $(10) | $— |
| Deferred income tax benefit (expense) | (547) | 495 |
| | | |
| Effective income tax rate | 0.6% | 1.6% |

Our effective tax rate differs from the statutory rates, primarily due to being structured as a master limited partnership, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states.

19. Commitments and Contingencies

Legal proceedings

Equity restructuring

On September 5, 2013, HPIP, our General Partner and the Partnership were named as defendants in an action filed by AIM challenging the Equity Restructuring. AIM Midstream Holdings, LLC v. High Point Infrastructure Partners, LLC, American Midstream GP, LLC and American Midstream Partners, LP (Civil Action No. 8803-VCP) was filed in the Court of Chancery of the State of Delaware. Among claims against the other parties to the litigation, the action asserts a claim of tortious interference with contract against the Partnership and sought either rescission of the Partnership's equity restructuring agreement executed on August 9, 2013 or, in the alternative, monetary damages.

On February 5, 2014, we, HPIP and our General Partner entered into a settlement (the "Settlement") with AIM Midstream Holdings regarding the action filed in Delaware Chancery Court by AIM Midstream Holdings. Under the Settlement, among other things:

- HPIP and AIM Midstream Holdings amended the LLC Amendment to, among other things, amend the Sharing Percentages (as defined therein) such that HPIP's sharing percentage thereafter is 95% and AIM Midstream Holdings's Sharing Percentage is 5%;
- HPIP transferred all of the 85.02% of our outstanding new IDRs held by HPIP to our General Partner such that our General Partner owns 100% of the outstanding new IDRs; and
- We issued to AIM Midstream Holdings a warrant to purchase up to 300,000 common units of the Partnership at an exercise price of $0.01 per common unit, which Warrant, among other terms, i) was exercisable at any time on or after February 8, 2014 until the tenth anniversary of February 5, 2014, ii) contained cashless exercise provisions and iii) contains customary anti-dilution and other protections. The Warrant was exercised on February 21, 2014.

Gloria System Matter

We were named in a lawsuit in the District Court of Jefferson Parish, Louisiana related to right of way maintenance and damages on our Louisiana Intrastate (Gloria) pipeline system related to a servitude agreement entered into by a predecessor in 1956. The landowner had sued us claiming that we have failed to maintain the pipeline right-of-way, allegedly causing erosion of the pipeline canal, erosion of levees, and deterioration of the adjacent marshland. The landowner sought damages for the cost to narrow the pipeline canal, rebuild the pipeline levees, and restore the damaged marsh.

Following negotiations, we entered into an agreement with the landowner during the fourth quarter of 2014 for the procurement of additional pipeline right-of-way and permits in order to rebuild sections of the levees and dams which will provide additional protection to portions of our Gloria System. We expect to incur up to $1.0 million of capital expenditures over the next twelve months in connection with this rebuilding.

Environmental matters

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to natural gas pipeline, NGL and crude pipelines and operations, as well as terminal operations and we could, at times, be subject to environmental cleanup and enforcement actions. We attempt to manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment.

Regulatory matters

On October 8, 2014, the Partnership reached an agreement in principle with customers regarding its Midla interstate pipeline that traverses Louisiana and Mississippi. The parties involved reached the agreement in principle in order to provide continued service to Midla's customers while addressing safety concerns with the existing pipeline.

Midla and the parties agreed that Midla may retire the existing 1920s vintage pipeline and replace the existing natural gas service with a new pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the "Natchez Line") to serve existing residential, commercial, and industrial customers. Customers not served by the new Natchez Line will be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service. The agreement is subject to final agreements and ongoing proceedings at the FERC.

Under the agreement in principle and subject to FERC approval, Midla will execute long-term agreements to recover its investment in the new Natchez Line.

Commitments and contractual obligations

Future non-cancelable commitments related to certain contractual obligations as of December 31, 2014, are presented below (in thousands):

| | Operating leases and service contracts | Asset Retirement Obligation | Total |
|---|---|---|---|
| 2015 | $3,428 | $— | $3,428 |
| 2016 | 2,204 | 6,884 | 9,088 |
| 2017 | 1,421 | — | 1,421 |
| 2018 | 1,306 | — | 1,306 |
| 2019 | 1,525 | — | 1,525 |
| Thereafter | 2,945 | 27,761 | 30,706 |
| | $12,829 | $34,645 | $47,474 |

For the years ended December 31, 2014, 2013 and 2012, total expenses related to operating leases, land site leases and right-of-way agreements were $5.8 million, $1.1 million, and $0.9 million, respectively.

20. Related-Party Transactions

Employees of our General Partner are assigned to work for us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by our General Partner to American Midstream, LLC, which, in turn, charges the appropriate subsidiary. Our General Partner does not record any profit or margin for the administrative and operational services charged to us. During the years ended December 31, 2014, 2013, and 2012, administrative and operational services expenses of $23.5 million, $14.2 million and $12.5 million, respectively, were charged to us by our General Partner. For the year ended December 31, 2014, 2013 and 2012, our General Partner incurred approximately $1.2 million, $1.8 million and $0.4 million of costs associated with certain business development activities, respectively. If the business development activities result in a project that will be pursued and funded by the Partnership, we will reimburse our General Partner for the business development costs related to that project.

During the second quarter of 2014, the Partnership and an affiliate of its General Partner entered into a Management Service Fee arrangement under which the affiliate pays a monthly fee to reimburse the Partnership for administrative expenses incurred on the affiliate's behalf. For the year ended December 31, 2014, the Partnership recognized $0.9 million in management fee income that has been recorded as a reduction to Selling, general and administrative expenses.

The High Point System, along with $15.0 million in cash, was contributed to us by HPIP in exchange for 5,142,857 Series A Units. Of the cash consideration paid by HPIP, approximately $2.5 million was used to pay certain transaction expenses of HPIP, and the remaining approximately $12.5 million was used to repay borrowings outstanding under the Partnership's former credit facility.

In January 2014, in connection with the acquisition of the Lavaca System, the Partnership issued 1,168,225 Series B Units to our General Partner. The net proceeds related to the issuance was $30.0 million.

In connection with the Blackwater Acquisition, our General Partner contributed the net assets of Blackwater which were recorded at their historical book value of $22.7 million for consideration of $63.9 million, of which $27.7 million was accounted for as a cash distribution to the General Partner. The consideration also included 125,500 limited partner units which were accounted for as a non-cash distribution to the General Partner at a fair value of $3.1 million. See Note 3 "Acquisitions" for more information.

On October 9, 2012, Blackwater entered into a Convertible Promissory Note (the "BWHD Note") with ArcLight Energy Partners Fund V, L.P. ("AL Fund V"), in the amount of $20.0 million. AL Fund V is a related party to the Partnership. The BWHD Note was paid off during the fourth quarter of 2013 as part of the Blackwater Acquisition.

## 21. Reporting Segments

Our operations are located in the United States and are organized into three reporting segments: i) Gathering and Processing, ii) Transmission and iii) Terminals.

### Gathering and Processing

Our Gathering and Processing segment provides "wellhead-to-market" services to producers of natural gas and oil, which include transporting raw natural gas from the wellhead through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs and selling or delivering pipeline quality natural gas and NGLs to various markets and pipeline systems.

### Transmission

Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, including local distribution companies, or LDCs, utilities and industrial, commercial and power generation customers.

### Terminals

Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including petroleum products, distillates, chemicals and agricultural products.

These segments are monitored separately by management for performance and are consistent with the Partnership's internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the results of each segment.

The following tables set forth our segment information for the periods indicated (in thousands):

| | Year Ended December 31, 2014 | | | |
|---|---|---|---|---|
| | Gathering and Processing | Transmission | Terminals | Total |
| Revenue | $ 203,616 | $ 88,189 | $ 15,504 | $ 307,309 |
| Gain (loss) on commodity derivatives, net | 1,091 | — | — | 1,091 |
| Total revenue | 204,707 | 88,189 | 15,504 | 308,400 |
| Operating expenses: | | | | |
| Purchases of natural gas, NGL's and condensate | 152,690 | 45,262 | — | 197,952 |
| Direct operating expenses | 23,783 | 15,577 | 6,342 | 45,702 |
| Selling, general and administrative expenses | | | | 23,103 |
| Equity compensation expense | | | | 1,536 |
| Depreciation, amortization and accretion expense | | | | 28,832 |
| Total operating expenses | | | | 297,125 |
| Gain (loss) on sale of assets, net | | | | (122) |
| Loss on impairment of property, plant and equipment | | | | (99,892) |
| Other expense | | | | (670) |
| Interest expense | | | | (7,577) |
| Earnings in unconsolidated affiliates | | | | 348 |
| Income tax benefit (expense) | | | | (557) |
| Income (loss) from operations of disposal groups, net of tax | | | | (611) |
| Net income (loss) | | | | (97,806) |
| Less: Net income (loss) attributable to noncontrolling interests | | | | 214 |
| Net income (loss) attributable to the Partnership | | | | $ (98,020) |
| Segment gross margin (b) | $ 50,817 | $ 42,828 | $ 9,162 | $ 102,807 |

| | Year Ended December 31, 2013 | | | |
|---|---|---|---|---|
| | Gathering and Processing | Transmission | Terminals (a) | Total |
| Revenue | $205,179 | $79,041 | $9,831 | $294,051 |
| Gain (loss) on commodity derivatives, net | 28 | — | — | 28 |
| Total revenue | 205,207 | 79,041 | 9,831 | 294,079 |
| Operating expenses: | | | | |
| Purchases of natural gas, NGL's and condensate | 168,574 | 46,479 | — | 215,053 |
| Direct operating expenses | 14,574 | 13,259 | 4,403 | 32,236 |
| Selling, general and administrative expenses | | | | 19,079 |
| Equity compensation expense | | | | 2,094 |
| Depreciation, amortization and accretion expense | | | | 30,002 |
| Total operating expenses | | | | 298,464 |
| Gain (loss) on involuntary conversion of property, plant and equipment | | | | 343 |
| Loss on impairment of property, plant and equipment | | | | (18,155) |
| Interest expense | | | | (9,291) |
| Income tax benefit (expense) | | | | 495 |
| Income (loss) from operation of disposal groups, net of tax | | | | (2,413) |
| Net income (loss) | | | | (33,406) |
| Less: Net income (loss) attributable to noncontrolling interests | | | | 633 |
| Net income (loss) attributable to the Partnership | | | | $(34,039) |
| Segment gross margin (b) | $36,985 | $32,408 | $5,428 | $74,821 |

| | Year Ended December 31, 2012 | | |
|---|---|---|---|
| | Gathering and Processing | Transmission | Total |
| Revenue | $ 152,339 | $ 52,529 | $ 204,868 |
| Gain (loss) on commodity derivatives, net | 3,400 | — | 3,400 |
| Total revenue | 155,739 | 52,529 | 208,268 |
| Operating expenses: | | | |
| Purchases of natural gas, NGL's and condensate | 117,956 | 36,516 | 154,472 |
| Direct operating expenses | 12,152 | 5,031 | 17,183 |
| Selling, general and administrative expenses | | | 14,309 |
| Equity compensation expense | | | 1,783 |
| Depreciation, amortization and accretion expense | | | 21,287 |
| Total operating expenses | | | 209,034 |
| Gain (loss) on involuntary conversion of property, plant and equipment | | | (1,021) |
| Gain (loss) on sale of assets, net | | | 123 |
| Interest expense | | | (4,570) |
| Income (loss) from operations of disposal groups | | | (18) |
| Net income (loss) | | | (6,252) |
| Less: Net income (loss) attributable to noncontrolling interests | | | 256 |
| Net income (loss) attributable to the Partnership | | | $ (6,508) |
| | | | |
| Segment gross margin (b) | $ 36,118 | $ 13,313 | $ 49,431 |

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Segment assets: | | |
| Gathering and Processing | 686,395 | 178,869 |
| Transmission | 132,767 | 131,136 |
| Terminals | 71,180 | 60,873 |
| Other (c) | 26,302 | 11,197 |
| Total assets | 916,644 | 382,075 |

(a) Terminals segment amounts are for the period from April 15, 2013 to December 31, 2013.

(b) Segment gross margin for our Gathering and Processing segment consists of revenue less purchases of natural gas, NGLs and condensate and COMA. Segment gross margin for our Transmission segment consists of revenue, less purchases of natural gas and COMA. Segment gross margin for our Terminals segment consists of revenue, less direct operating expenses. Gross margin consists of the sum of the segment gross margin amounts for each of these segments. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow from operations as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner. Effective October 1, 2012, we changed our segment gross margin measure to exclude construction, operating and maintenance agreement ("COMA") income. Effective January 1, 2011, we changed our segment gross margin measure to exclude unrealized non-cash mark-to-market adjustments related to our commodity derivatives. Effective April 1, 2011, we changed our segment gross margin measure to exclude realized early termination costs on commodity derivatives.

(c) Other assets not allocable to segments consist of investment in unconsolidated affiliate, corporate leasehold improvements, and other assets.

For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use gross margin to evaluate our operating performance, please read Item 7. "Management's Discussion and Analysis, How We Evaluate Our Operations."

The following table summarizes the percentage of revenue earned from those customers in each segment that exceed 10% of the Partnership's consolidated segment's revenue for the each of the periods presented below:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| Gathering and Processing: | | | | | | |
| Customer A | 33 | % | 43 | % | 40 | % |
| Customer B | 12 | % | 19 | % | 11 | % |
| Customer D | — | | — | % | 12 | % |
| Other | 55 | % | 38 | % | 37 | % |
| Total | 100 | % | 100 | % | 100 | % |
| Transmission: | | | | | | |
| Customer C | 43 | % | 39 | % | 50 | % |
| Customer D | 16 | % | 16 | % | 22 | % |
| Customer E | — | | — | % | 10 | % |
| Other | 41 | % | 45 | % | 18 | % |
| Total | 100 | % | 100 | % | 100 | % |
| Terminals: | | | | | | |
| Customer F | 19 | % | 20 | % | N/A | |
| Customer B | 20 | % | 17 | % | N/A | |
| Customer G | 15 | % | 16 | % | N/A | |
| Customer H | 11 | % | 13 | % | N/A | |
| Other | 35 | % | 34 | % | N/A | |
| Total | 100 | % | 100 | % | — | |

22. Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2014 and 2013 are as follows (in thousands, except per unit amounts):

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter (b) |
|---|---|---|---|---|
| Year Ended December 31, 2014 | | | | |
| Total revenues | $80,238 | $77,680 | $70,305 | $80,177 |
| Gross margin (a) | 23,081 | 22,167 | 21,332 | 36,227 |
| Operating income (loss) | 2,450 | 734 | (290) | (91,633) |
| Net income (loss) from continuing operations | 558 | (1,095) | (2,397) | (94,261) |
| Income (loss) from operations of disposal groups | (50) | (506) | (26) | (29) |
| Net income (loss) attributable to noncontrolling interest | 108 | 66 | 33 | 7 |
| Net income (loss) attributable to the Partnership | 400 | (1,667) | (2,456) | (94,297) |
| General Partner's Interest in net income (loss) | 7 | (22) | (32) | (1,232) |
| Limited Partners' Interest in net income (loss) | $393 | $(1,645) | $(2,424) | $(93,065) |
| | | | | |
| Limited Partners' income (loss) per unit: | | | | |
| Income (loss) from continuing operations | $(0.31) | $(0.55) | $(0.58) | $(4.98) |
| Income (loss) from discontinued operations | (0.01) | (0.04) | — | — |
| Net income (loss) | $(0.32) | $(0.59) | $(0.58) | $(4.98) |
| Year Ended December 31, 2013 | | | | |
| Total revenues | $62,599 | $77,191 | $77,519 | $76,770 |
| Gross margin (a) | 12,705 | 18,317 | 20,908 | 22,891 |
| Operating income (loss) | (1,661) | (17,841) | (104) | (2,591) |
| Net income (loss) from continuing operations | (3,392) | (20,057) | (2,526) | (5,018) |
| Income (loss) from operations of disposal groups | (6) | (1,869) | (15) | (523) |
| Net income (loss) attributable to noncontrolling interest | 155 | 188 | 190 | 100 |
| Net income (loss) attributable to the Partnership | (3,553) | (22,114) | (2,731) | (5,641) |
| General Partner's Interest in net income (loss) | (70) | (905) | (221) | (209) |
| Limited Partners' Interest in net income (loss) | $(3,482) | $(21,209) | $(2,510) | $(5,433) |
| | | | | |
| Limited Partners' income (loss) per unit: | | | | |
| Income (loss) from continuing operations | $(0.39) | $(4.01) | $(0.81) | $(1.43) |
| Income (loss) from discontinued operations | 0.01 | (0.20) | 0.01 | — |
| Net income (loss) | $(0.38) | $(4.21) | $(0.80) | $(1.43) |

(a) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use gross margin to evaluate our operating performance, please read Item 7. "Management's Discussion and Analysis, How We Evaluate Our Operations."

(b) The Partnership record an immaterial out-of-period adjustment in the fourth quarter of 2014 to account for the items associated with the material weakness described in Item 9A. Management's Annual Report over Internal Control over Financial Reporting.

23. Subsequent Events

Distribution

On January 22, 2015, we announced that the board of directors of our General Partner declared a quarterly cash distribution of $0.4725 per unit for the fourth quarter ended December 31, 2014, or $1.89 per unit on an annualized basis. The cash distribution was paid on February 13, 2015, to unitholders of record as of the close of business on February 6, 2015, together with our General Partner.