American Midstream Partners, LP
Form 10-K
April 16, 2013

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, 2012

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 (State or other jurisdiction of incorporation or organization)	27-0855785 (I.R.S. Employer Identification No.)
1614 15th Street, Suite 300 Denver, CO (Address of principal executive offices)	80202 (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 of 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.

Yes o No x

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

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

There were 4,645,453 common units and 4,526,066 subordinated units of American Midstream Partners, LP outstanding as of March 31, 2013. Our common units trade on the New York Stock Exchange under the ticker symbol “AMID.”

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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,” “f 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 and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- 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 natural gas supplies to our gathering and processing systems;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; 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”). 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:

ASC	Accounting Standards Codification; trademark of the Financial Accounting Standards Board (FASB).
Bbl	Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.
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.
EBITDA	Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is considered to be a non-GAAP measurement.
FERC	Federal Energy Regulatory Commission.
Fractionation	Process by which natural gas liquids are separated into individual components
GAAP	General Accepted Accounting Principles: Accounting principles generally accepted in the United States of America.
Gal	Gallons.
MBbl	One thousand barrels.
MMBbl	One million barrels.
MMBtu	One million British thermal units.
Mcf	One thousand cubic feet.
MMcf	One 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.
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.

PART I
Item 1. Business
Overview
We are a growth-oriented Delaware limited partnership that was formed by American Infrastructure MLP Fund, L.P. ("AIM") in August 2009 to own, operate, develop and acquire a diversified portfolio of natural gas midstream energy assets. We are engaged in the business of gathering, treating, processing, fractionating and transporting natural gas through our ownership and operation of ten gathering systems, four processing facilities and a 50% non-operating interest in a fifth plant, two interstate pipelines and four intrastate pipelines. Our primary assets, which are strategically located in Alabama, Louisiana, Mississippi, Tennessee and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. As of December 31, 2012, we operate approximately 1,400 miles of pipelines that gather and transport over 600 MMcf/d of natural gas.
Our operations are organized into two segments: (i) Gathering and Processing and (ii) Transmission. In our Gathering and Processing segment, we receive fee-based and fixed-margin compensation for gathering, 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. We own four processing facilities that collectively produced an average of approximately 49.9 Mgal/d and 54.5 Mgal/d of gross NGLs for years ended December 31, 2012 and 2011, respectively.

Effective July 1, 2012, we acquired an 87.4% undivided interest in the Chatom system which processed 8.1 MMcf/d from eight connected wells to our account in 2012. Average NGL and condensate sales for the year ended December 31, 2012 were approximately 20.0 Mgal/d. Effective November 1, 2011, we acquired a 50% undivided non-operating interest in the Burns Point Plant which produced 9.6 Mgal/d to our account in 2012. In addition, in connection with our elective processing arrangements, we contract for processing capacity at a third-party plant where we have the option to process natural gas that we purchase. Under these arrangements, we sold an average of approximately 27.9 Mgal/d and 27.4 Mgal/d of net equity NGL volumes for the years ended December 31, 2012 and 2011, respectively.
We also receive fee-based and fixed-margin compensation in our Transmission segment 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.
For the years ended December 31, 2012 and 2011, we generated $50.6 million and $45.9 million of gross margin, respectively, of which $37.2 million and $32.1 million, respectively, was segment gross margin generated in our Gathering and Processing segment and $13.3 million and $13.7 million, respectively, was segment gross margin generated in our Transmission segment. For the years ended December 31, 2012 and 2011, $24.5 million and $27.1 million, or 48.5% and 59.0%, respectively, of our gross margin was generated from fee-based, fixed-margin and firm and interruptible transportation contracts with respect to which we have little or no direct commodity price exposure. For a definition of gross margin and a reconciliation of gross margin to its most directly comparable financial measure calculated in accordance with GAAP, please read "Selected Historical Financial and Operating Data — Non-GAAP Financial Measures."
On April 15, 2013, the Partnership, our general partner and AIM Midstream Holdings, LLC, an affiliate of American Infrastructure MLP Fund, entered into agreements with High Point Infrastructure Partners, LLC, an affiliate of ArcLight Capital Partners, LLC ("High Point"), pursuant to which High Point (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 million in cash to us in exchange for 5,142,857 convertible preferred units (the "Series A Preferred Units") issued by the Partnership. As a result of these transactions, which were also consummated on April 15, 2013, High Point acquired both control of our general partner, which holds all of our general partner units and incentive distribution rights, and a majority of our outstanding limited partnership interests. The midstream assets contributed by High Point consist of approximately 700 miles of natural gas and liquids pipeline assets located in southeast Louisiana and the shallow water and deep shelf Gulf of Mexico. These midstream assets gather natural gas from both onshore and offshore

producing regions around southeast Louisiana. The onshore footprint is Plaquemines and St. Bernard's Parish, LA. 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 midstream assets are comprised of FERC-regulated transmission assets and non-jurisdictional gathering assets, both of which accept natural gas from well production and interconnected pipeline systems. High Point delivers the natural gas to the Toca Gas Processing Plant, operated by Enterprise, where the products are processed and the residue gas sent to an unaffiliated interstate system owned by Kinder Morgan. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Recent Developments — ArcLight Transactions"

Business Strategies

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability of our business. We expect to achieve this objective by executing the following strategies:

- 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 have potential for attractive returns.
- Attract Additional Volumes to Our Systems. We intend to attract new volumes of natural gas to our systems from existing and new customers by continuing to provide superior customer service and aggressively marketing our services to additional customers in our areas of operation. In addition, we intend to rebuild or reestablish relationships with customers that were potentially under-served by the previous owner of our assets. For example, in 2010 we were able to contract with a customer on our Gloria system for volumes of natural gas that it had decided to have gathered and processed by alternative means prior to our acquisition of the system. We have available capacity on a majority of our systems, and as a result, we can accommodate additional volumes at a minimal incremental cost.
- Pursue Strategic and Accretive Acquisitions. We plan to pursue accretive acquisitions of energy infrastructure assets 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. For example, in November 2011, we acquired from Marathon Oil Company a fifty percent (50%) non-operating working interest in the Burns Point Plant. The Burns Point Plant is located in St Mary Parish, LA and to which our Quivira Gathering system is connected. In July 2012, we acquired from affiliates of Quantum Resources Management, LLC., a 87.4% undivided interest in the Chatom system. The Chatom system is located in Alabama and is located 15 miles from our Bazor Ridge system.
- Develop strategic and accretive new asset platforms. We plan selectively to pursue the development of new complementary midstream asset platforms in our current operating regions and in new midstream assets that provide attractive returns in regions where we currently do not have any assets. We believe it is important to our current and potential customers that we act as their midstream partner beyond our current asset footprint, so it is important to have the ability to develop new infrastructure for our customers where they deem it necessary in an accretive and economically attractive manner. As our customers move to produce new areas or develop new end use markets, we seek to provide solutions for their midstream needs. We will develop assets in our current lines of business, but may pursue opportunities in new but related business lines as well.
- Manage Exposure to Commodity Price Risk. We will manage our commodity price exposure by targeting a contract portfolio that is weighted towards firm transportation, fee-based and fixed-margin contracts while mitigating direct commodity price exposure by employing a prudent hedging strategy. For the years ended December 31, 2012 and 2011, approximately 48.5% and 59.0%, respectively, of our gross margin was generated from firm transportation, fee-based and fixed-margin contracts that, together with our percent-of-proceeds contracts and hedging activities, generated relatively stable cash flows. As of December 31, 2012, we have hedged approximately 55% of our expected 2013 net equity natural gas, NGL and condensate volumes with a combination of swaps, puts and collars for the specific commodity risk to which we are exposed. With respect to our exposure to natural gas prices, we are generally 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.
- 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 markets environments.

- Continue our Commitment to Safe 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 handle natural gas and NGLs for our customers safely, while striving to minimize the environmental impact of our operations. To this end, we implemented a safety performance program, including an integrity management program, upon our formation in 2009 and implemented 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 many of our larger competitors. Given the current size of our business, these opportunities may have a larger 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, where we can pursue the development of a new system that will be an impactful new asset to our company that would not be meaningful enough to gain the attention of our larger competitors.

- 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 five 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 supplies and to capture new customers that are underserved by our competitors. We continue to see drilling activity on and around our systems, and we believe that our assets are strategically positioned to capitalize on the resurgent drilling activity, increased demand for midstream services and growing commodity consumption in the 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 add capacity economically to our systems; and
  - many of our systems have multiple downstream interconnects that provide our customers with multiple market delivery options, thus causing our systems to be more attractive versus 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 of 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 more than 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 our Long-Term Incentive Plan.

Our Assets

We own and operate ten gathering systems, four processing facilities, two interstate pipelines and our intrastate pipelines. We also own a 50% undivided interest in the Burns Point Plant, a natural gas processing plant. Our assets are primarily located in Alabama, Louisiana, Mississippi, and Texas. We organize our operations into two business segments: (i) Gathering and Processing; and (ii) Transmission.

The following table provides information regarding our segments and assets as of December 31, 2012 and for the years ended December 31, 2012 and 2011.

	System Type	Contract Type (f)	Miles	Approximate Number of Connected Wells / Receipt Points	Compression (Horsepower)	Approximate Design Capacity (MMcf/d)	Approximate Average Throughput (MMcf/d) Year Ended December 31, 2012	2011
Gathering and Processing								
Gloria	Gathering, Processing (e)	Fee (g), POP	110	62	1,877	60	38.3	43.3
Chatom (a)	Gathering Processing Fractionating	Fee, POP	29	8	5,000	25	8.1	—
Lafitte	Gathering	Fee (g)	41	46	—	71	22.6	19.3
Bazor Ridge	Gathering Processing	Fee, POP	160	46	6,287	22	12.6	13.4
Quivira	Gathering	Fee	34	17	—	140	79.1	110.8
Burns Point Plant (b)	Processing	POP	—	3	11,000	200	98.2	21.8
Offshore Texas	Gathering	Fee (g)	56	23	—	100	15.2	18.2
Other (c)	Gathering, Processing	Fee (g), POP	189	445	5,156	153	25.2	24.1
Total			619	650	29,320	771	299.3	250.9
Transmission								
Bamagas	Intrastate	FT	52	2	—	450	151.3	163.9
AlaTenn	Interstate	FT, IT	295	4	3,665	200	46.1	46.0
Midla	Interstate	FT, IT	370	9	3,600	198	130.4	95.1
MLGT	Intrastate	FT, IT (g)	54	7	—	170	44.5	51.9
Other (d)	Intrastate	FT, IT	82	6	—	336	26.2	24.2
Total			853	28	7,265	1,354	398.5	381.1

(a) We have included approximate average throughput for our account of the acquired 87.4% undivided interest in the Chatom system, effective July 1, 2012.

(b) The Burns Point Plant is connected to 3 pipelines, including the Quivira System, which are supported by over 40 wells and central delivery points. We have included approximate average throughput for our account of the acquired 50% undivided interest in the Burns Point Plant, effective November 1, 2011.

(c) Includes our Alabama Processing, Fayette, Magnolia, Heidelberg and Madison systems.

(d) Includes our Trigas and Chalmette systems.

(e) Although the Gloria system is comprised solely of gathering pipelines, we generate a substantial portion of our Gloria revenue by processing natural gas for our own account at the Toca processing plant in connection with our elective processing arrangements. We do not own the Toca processing plant, but we have the contractual ability to process the natural gas for our own account and retain the majority of the proceeds derived from the sale of the residue natural gas and resulting NGLs. Please see "— Gathering and Processing Segment — Gloria System."

(f) In this table, fee refers to fee-based contracts, POP refers to percent-of-proceeds contracts, FT refers to firm transportation contracts and IT refers to interruptible transportation contracts.

(g) Because 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 in our Gathering and Processing segment and the fee earned in our interruptible transportation arrangements in our Transmission segment, we have included the fixed-margin arrangements in those categories.

Gathering and Processing Segment

General

Our Gathering and Processing segment is an integrated midstream natural gas system that provides the following services to our customers:

- gathering;
- compression;

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

We own one processing plant on our Bazor Ridge system, one on our Chatom system and two on our Alabama Processing system. In addition, we own a 50% non-operating interest in the Burns Point Plant and have the right to contract for processing services for our own account at a plant that is connected to our Gloria system, the Toca plant. The Toca plant is owned and operated by Enterprise Products Partners, LP ("Enterprise") which also operates the Burns Point Plant. Our Bazor Ridge processing plant, the Chatom processing plant, the Burns Point plant and the Toca plant are all cryogenic processing plants. These types of processing plants represent the latest generation of processing techniques, using extremely low temperatures and high pressures to optimize the extraction of NGLs from the raw natural gas stream.

We generally derive revenue in our Gathering and Processing segment from fee-based, fixed-margin and POP arrangements, whether for our producer and supplier customers or our own account. We have no keep-whole arrangements with our customers. On our Gloria, Lafitte and Offshore Texas systems and other, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and subsequently transport that natural gas to delivery points on our systems at which we sell the natural gas at the same undiscounted index price thereby earning a fixed margin on each transaction. We regard the segment gross margin we earn with respect to those purchases and sales a "fixed-margin" and as the economic equivalent of a fee for our transportation service, and as such, we include these transactions in the category of fee-based contractual arrangements. In order to minimize commodity price risk we face in these transactions, we match sales with purchases at the index price on the date of settlement. For the year ended December 31, 2012, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 30.2% and 69.8%, respectively, of our segment gross margin for this segment. For the year ended December 31, 2011, our fee-based and fixed-margin arrangements and our POP arrangements accounted for approximately 41.2% and 58.8%, respectively, of our segment gross margin for this segment.

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. As a result, we connected ten new supply sources in 2012 to systems in our Gathering and Processing segment, including connections of individual wells, as well as central delivery points.

Our Gathering and Processing assets are located in Alabama, Louisiana and Mississippi and in shallow state and federal waters in the Gulf of Mexico off the coasts of Louisiana and Texas.

Gloria System

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 110 miles of pipeline with diameters ranging from three to 16 inches and three compressors with a combined size of 1,877 horsepower. The Gloria system has a design capacity of approximately 90 MMcf/d, but is currently limited by compression horsepower at the Gloria Compressor Station to approximately 60 MMcf/d. Average throughput on the Gloria system for the year ended December 31, 2012 was 38.3 MMcf/d from approximately 62 connected wells and an interconnect with our Lafitte system. Average throughput on the Gloria system increased to approximately 43.3 MMcf/d from 59 connected wells for the year ended December 31, 2011 due to excess volumes from our Lafitte system, primarily resulting from incremental volumes from the interconnect between the Lafitte system and Tennessee Gas Pipeline Company, LLC ("TGP"), an interstate pipeline owned by Kinder Morgan as a result of line looping, interconnection and compression projects completed in 2012. For more information about the excess natural gas from our Lafitte system, please read "— Lafitte System."

The Gloria system gathers natural gas from onshore oil and natural gas wells producing from the Gulf Coast region of Louisiana. Production is derived from a variety of reservoirs and ranges from dry natural gas to rich associated natural gas. Well decline rates are variable in this area, but it is common practice for producers to mitigate declines in production with workovers and re-completions of existing wells. An average of two-three wells per year were connected to the Gloria system over the last three years, with three wells connected during the year ended December 31, 2012. Producers generally bear the cost of connecting their wells to our Gloria system.

Toca Plant and Our Elective Processing Arrangements. The Toca plant is a cryogenic processing plant with a design capacity of approximately 1.1 Bcf/d that is located in St. Bernard Parish in Louisiana and operated by Enterprise. We entered into a new POP processing contract with Enterprise in July 2011 that replaced two month-to-month POP processing contracts with Enterprise and allows us to continue to process raw natural gas through the Toca plant, whether for our customers or our own account. This new contract has an initial term of seven years and covers volumes from both our Gloria and Lafitte systems. The new contract contains a tiered-pricing structure based on the volume of natural gas processed under which Enterprise retains a percentage of the NGLs produced by the Toca plant as payment for its processing services. Natural gas that is processed at the Toca plant is transported to end users via the Sonat pipeline directly and through various interconnects downstream of the Toca plant. Sonat is the primary pipeline into which Toca volumes are currently delivered. Sonat has sold its Gulf of Mexico gathering facilities located upstream of the Toca Plant to High Point Gas Transmission, LLC.

Our month-to-month contracts with producers on the Gloria and Lafitte systems, as well as our ability to purchase natural gas at the Lafitte/TGP interconnect, provide us with the flexibility to decide whether to process natural gas through the Toca plant and capture processing margins for our own account or deliver the natural gas into the interstate pipeline market at the inlet to the Toca plant, and we make this decision based on the relative prices of natural gas and NGLs on a monthly basis. We refer to the flexibility built into these contracts as our elective processing arrangements. Due to currently strong processing margins, we currently process 100% of the natural gas purchased on the Gloria system, as well as any excess natural gas purchased via the Lafitte/TGP interconnect in excess of the needs of ConocoPhillips at the Alliance Refinery. Based on publicly available information, we believe that the Toca plant has sufficient capacity available to accommodate additional volumes from the Gloria system.

Chatom System

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 by borrowings under our June 2012 amended credit facility.

The Chatom system consists of a 25 MMcf/d refrigeration processing plant, a 1,100 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 29 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 producing in Alabama and Mississippi.

We have POP arrangements with each of the customers operating these wells. After processing, the residue natural gas is sold and delivered to Clarke Mobile, a local distribution company in Alabama, at a Florida Gas Transmission Zone 3 index-based price. The NGLs are fractionated at the Chatom system and then sold at the tailgate of the plant to various counterparties at a Mt. Belvieu index-based price. Condensate in the inlet natural gas stream is separated at the plant and sold at the tailgate to Shell Trading (US) Company at a Louisiana Light Sweet index-based price. Sulfur is recovered from the inlet natural gas stream and sold to a local sulfur consumer at a Tampa index-based price.

Additionally, the Chatom system fractionates NGLs from a third party supplier under a long-term fractionation agreement. The contract consists of a fee-based component as well as an arrangement to purchase and resell the fractionated NGLs at indexed pricing.

Average natural gas throughput on the Chatom system for the year ended December 31, 2012 was approximately 8.1 MMcf/d from eight connected wells. Average NGL and condensate sales for the year ended December 31, 2012 were approximately 20.0 Mgal/d.

Lafitte System

The Lafitte gathering system consists of approximately 41 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 ConocoPhillips Corporation, or ConocoPhillips. Average throughput on the Lafitte system for the years ended December 31, 2012 and 2011 was 22.6 MMcf/d and 19.3 MMcf/d, respectively, from approximately 46 connected wells and an interconnect with TGP that was completed in December 2010. 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 ConocoPhillips at the Alliance Refinery is delivered to our Gloria system.

Like our nearby Gloria system, the Lafitte system gathers natural gas from onshore oil and natural gas wells producing from the Gulf Coast region of Louisiana. An average of one well per year was connected to the Lafitte system over the last three years, with two wells connected during the year ended December 31, 2012. Producers generally bear the cost of connecting their wells to our Lafitte system.

TGP Interconnect. In December 2010, we completed an interconnect between our Lafitte pipeline and the TGP interstate system. This interconnect provides a redundant source of natural gas supply for the ConocoPhillips Alliance Refinery to the extent that the Lafitte native production is insufficient to supply the needs of the refinery and provides us with increased operational flexibility on our Gloria and Lafitte systems. To the extent that there is excess supply that the refinery does not consume, we purchase those volumes to be sold into Sonat pursuant to a fixed-margin arrangement or to be processed at the Toca processing facility pursuant to elective processing arrangements.

Bazor Ridge System

The Bazor Ridge gathering and processing system consists of approximately 160 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 and four inlet and one discharge compressor with approximately 5,218 of combined horsepower. We upgraded the turbo expander at the Bazor Ridge processing plant in June 2010, which resulted in a significant improvement in the plant's NGL recoveries and provided us with greater operating flexibility during changing commodity price environments. We have POP arrangements with each of our customers on the Bazor Ridge system that generally include a fee-based element for gathering and treating services. After processing, the residue natural gas is sold and delivered into the Destin Pipeline system, an interstate pipeline operated by Destin Pipeline Company, L.L.C., which has connections with a number of other interstate pipeline systems. We sell the NGLs we recover at the truck rack at the tailgate of the Bazor Ridge processing plant to Dufour Petroleum LP, an affiliate of Enbridge, pursuant to a month-to-month contract or transport them to our Chatom system for fractionation and sale. The NGLs are sold on a Mt. Belvieu index-based price. Average throughput on the Bazor Ridge plant for the year ended December 31, 2012 was approximately 12.6 MMcf/d from 46 connected wells. Average throughput increased from the prior year and was approximately 13.4 MMcf/d for the year ended December 31, 2011 as a result of the completion of the Winchester lateral, which we describe below, in November 2010.

Winchester Lateral. In 2010, we built a new eight-inch diameter pipeline consisting of approximately nine miles of pipe, called the Winchester lateral, to serve the natural gas wells located in Wayne County, Mississippi owned by Venture Oil & Gas, Inc., ("Venture"), and other producers. The Winchester lateral allowed us to increase the effective throughput capacity of the Bazor Ridge gathering system by approximately 200% to approximately 25 MMcf/d. In conjunction with the construction of the Winchester lateral, we negotiated a five-year acreage dedication from Venture.

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. An average of one to two wells per year was connected to our Bazor Ridge gathering system over the last three years, with 4 wells connected during the year ended December 31, 2012. Despite the low number of new wells connected, the generally stable production and relatively modest decline rates from this formation allow us to maintain steady throughput on our Bazor Ridge system. Given the recent and current commodity price environment for crude oil, we expect continued increases in drilling activity and resulting production in this area during 2013.

Quivira System

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. The Quivira system has a design capacity of approximately 140 MMcf/d. This system also includes an onshore condensate handling facility at Bayou Sale, Louisiana that is upstream of the Burns Point Plant. Residue natural gas is sold into TGP, SONAT or the Gulf South Pipeline system, an interstate pipeline owned by Boardwalk Pipeline Partners, LP.

The Quivira system is partially subscribed under a firm transportation arrangement through 2014, although a substantial proportion of the revenue is derived from volumetric and fee-based charges. Existing production in our gathering area above our current system capacity is transported on other systems that we believe offer producers less attractive economic alternatives to our customers. Average throughput on the Quivira system for the year ended December 31, 2011 was approximately 110.8 MMcf/d from 16 connected wells. Average throughput decreased to approximately 79.1 MMcf/d for the year ended December 31, 2012 as a result of production shut-ins and changes to production profiles associated with an interconnect to a gathering system owned and operated by a certain producer. The Quivira system provides gathering services for natural gas wells and associated natural gas produced from crude oil wells operated by major and independent producers targeting multiple conventional production zones in the shallow waters of the Gulf of Mexico. Wells in this area have historically exhibited relatively low rates of decline throughout the life of the wells. The natural gas produced from these wells is typically natural gas with condensate. An average of two wells per year were connected to the Quivira system over the last three years. No wells were connected during the year ended December 31, 2012. Producers generally bear the cost of connecting their wells to our Quivira system.

Burns Point Plant

Effective November 1, 2011, we acquired a 50% undivided interest in the Burns Point Plant from Marathon Oil Company. The remaining 50% undivided interest is owned by the plant operator, Enterprise. The plant, which is an unincorporated venture, is governed by a construction and operating agreement.

The plant is located in St. Mary Parish, Louisiana, and processes raw natural gas using a cryogenic expander. The plant inlet volumes are sourced from offshore natural gas production via our Quivira system, Gulf South pipelines and onshore from individual producers near the plant. Our Quivira system supplied up to approximately 85% of the inlet volume to the plant during 2012. The residue gas is transported, via pipeline to Gulf South, SONAT and Tennessee Gas Pipeline and the Y-grade liquid is transported via pipeline to K/D/S Promix, LLC ("Promix"), an Enterprise operated fractionator. The Burns Point plant is designed to process up to 200 MMcf/d but is currently limited to 165 MMcf/d due to compression constraints. The acquisition complemented our existing assets given the location of the Plant in comparison to the Quivira system.

In 2012, the average throughput at Burns Point was 98.2 MMcf/d and the average NGLs for our account was 9.6 Mgal/d.

The plant is not a legal entity but rather an asset that is jointly owned by Enterprise and us. We acquired an interest in the asset group and do not hold an interest in a legal entity. Each of the owners in the asset group is 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.

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. The Offshore Texas system provides gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico region offshore Texas.

The Offshore Texas system consists of approximately 56 miles of pipeline with diameters ranging from six to 16 inches and a design capacity of approximately 100 MMcf/d. Additionally, the Offshore Texas system has two onshore separation and dehydration units, each with a capacity of approximately 40 MMcf/d, that remove water and other impurities from the gathered natural gas before delivering it to our customers. The GIGS system originates offshore of Brazoria County, Texas in Galveston Island Block 343 and connects onshore to the Houston Pipeline system, an intrastate pipeline owned by Energy Transfer Partners, L.P. The Brazos system originates offshore of Brazoria County, Texas in Brazos Block 366 and connects onshore to the Dow Pipeline system, an intrastate pipeline owned by Dow Chemical Company. Substantially all of the natural gas gathered on the Brazos system is delivered to Dow Chemical for use in its chemical plant located in Freeport, Texas pursuant to a month-to-month contract. Dow consumes significantly more natural gas than is provided by the Brazos system and we believe Dow may purchase additional volumes from the Brazos system.

Average throughput on the Offshore Texas system for the years ended December 31, 2012 and 2011 was 15.2 MMcf/d and 18.2 MMcf/d, respectively from approximately 22 connected wells.

All of the wells in this area are natural gas wells producing from the Gulf of Mexico shelf offshore Texas. An average of two wells per year were connected to the Offshore Texas system over the last three years. No wells were connected during the year ended December 31, 2012. Producers generally bear the cost of connecting their wells to our Texas Offshore system.

Other Gathering and Processing Assets

Alabama Processing. The Alabama Processing system consists of two small skid-mounted treating and processing plants that we refer to, individually, as Atmore and Wildfork. These treating and processing plants are located in Escambia and Monroe Counties of Alabama, respectively, and have design capacities of 3 MMcf/d and 7 MMcf/d, respectively. The Atmore and Wildfork plants processed an average of 1.1 MMcf/d and 0.2 MMcf/d of natural gas, respectively, during the year ended December 31, 2012 and an average of 1.3 MMcf/d and 0.2 MMcf/d, respectively, during the year ended December 31, 2011.

Magnolia System. The Magnolia gathering system is a Section 311 intrastate pipeline that gathers coalbed 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 trunklines ranging from six to 24 inches in diameter and one compressor station with 3,328 horsepower. The Magnolia system has a design capacity of approximately 120 MMcf/d. Average throughput on the Magnolia system for the years ended December 31, 2012 and 2011 was approximately 15.5 MMcf/d and 16.9 MMcf/d, respectively. The Magnolia system is also strategically located in the Floyd shale formation, a currently underdeveloped play that may have significant production potential in a higher natural gas price environment.

Our other gathering and processing systems include the Fayette and Heidelberg gathering systems, located in Fayette County, Alabama and Jasper County, Mississippi, respectively. The design capacities for these systems are approximately 5 MMcf/d and approximately 18 MMcf/d, respectively. Average throughput for these systems was approximately 0.5 MMcf/d and approximately 4.0 MMcf/d, respectively, during the year ended December 31, 2012, and approximately 0.5 MMcf/d and approximately 5.3 MMcf/d, respectively, during the year ended December 31, 2011.

Growth Opportunities

In our Gathering and Processing segment, we continually seek new sources of raw natural gas supply to increase the throughput volume on our gathering systems and through our processing plants. In addition, we seek to identify and evaluate economically attractive organic expansion and asset acquisition opportunities that leverage our existing asset footprint and strategic relationships with our customers. We also plan to opportunistically pursue strategic and accretive acquisitions within the midstream energy industry that are complementary to our existing asset base or that provide attractive potential returns in new operating regions or business lines. We are evaluating the following growth opportunities:

- the construction of new pipelines and the addition of incremental compression to the Gloria system to accommodate potential new production from our current customers and to extend our asset footprint to reach new areas with existing production;
- the re-commissioning of our stranded Montegut lateral with the potential construction of new pipeline interconnects and new pipeline laterals to provide access to areas of existing production that we do not currently serve, potential access to a third-party processing plant, and takeaway capacity for new production areas;
- the construction of a new pipelines on the Bazor Ridge system to accommodate new drilling activity;
- new pipelines and interconnections on our Quivira system to access available and potential new production volume;
- facility improvements to the fractionator on our Chatom system to increase available fractionation capacity;
- the optimization of the Burns Point processing plant to improve operating efficiencies, enhance NGL recoveries, and increase plant throughput; and
- the development of new gathering systems and processing plants in areas not currently served by our assets.

Customers

Substantially all of the natural gas produced on our Lafitte system is sold to ConocoPhillips for use at its Alliance Refinery in Plaquemines Parish, Louisiana under a contract that expires in 2023. 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. We have a weighted-average remaining life of approximately two years on our fee-based contracts in this segment. The weighted-average remaining life on our POP contracts in this segment is approximately four years. For the year ended December 31, 2012, our Gathering and Processing segment derived 40%, 12% and 11% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Shell, respectively. For the year ended December 31, 2011, our Gathering and Processing segment derived 55%, 16% and 9% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Dow Hydrocarbons and Resources, 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 to customers such as local distribution companies, or LDCs, electric utilities or 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 generally 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 and multiple counties in Mississippi, Alabama and Tennessee.

In our Transmission segment, we contract with customers to provide firm and interruptible transportation services. In addition, we have a fixed-margin arrangement on our MLGT system whereby we purchase and sell the natural gas that we transport.

For our Midla and AlaTenn 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, we agree to discount services or in certain cases we enter into negotiated rate agreements that, with FERC approval, 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.

The table below sets forth certain information regarding the assets, contracts and revenue for each of the major systems comprising our Transmission segment, as of and for the year ended December 31, 2012:

Asset	Tariff Revenue Composition Firm Transportation Contracts Capacity Reservation Charges	Variable Use Charges	Interruptible Transportation Contracts	Percent of Design Capacity Subscribed Under Firm Transportation Contracts	Weighted Average Remaining Contract Life (in years)
Bamagas	100%	—	—	44%	8
AlaTenn	89%	3%	7%	26%	1
Midla	82%	2%	16%	100% (a)	1
MLGT(b)	—	—	100%	15%	<1

(a) Represents volumes subscribed under firm transportation contracts and design capacity on the mainline of our Midla system.
(b) Included fixed margin arrangements.

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 owned by Calpine Corporation, or Calpine, 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.

Average throughput on the Bamagas system for the years ended December 31, 2012 and 2011 was approximately 151.3 MMcf/d and 163.9 MMcf/d, respectively. Currently, 100% of the throughput on this system is contracted under long-term firm transportation agreements. Calpine Corporation is the sole customer on the Bamagas system, with 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.

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 295 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 four receipt and approximately 61 delivery 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. Average throughput on the AlaTenn system for the years ended December 31, 2012 and 2011 was approximately 46.1 MMcf/d and 46.0 MMcf/d, respectively.

Midla System

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. Our Midla system also has interconnects to Centerpoint, TGP and Sonat along a high-pressure lateral at the north end of the system, called the T-32 lateral.

Our Midla system is strategically located near the Perryville Hub, which is a major hub for natural gas produced in the Louisiana and broader Gulf Coast region, including natural gas from the Haynesville shale, Barnett shale, Fayetteville shale, Woodford shale and Deep Bossier formations of Northern Louisiana, Central Texas, Northern Arkansas, Eastern Oklahoma and East Texas, respectively. The Midla system is connected to nine receipt and 19 delivery points. Due to the numerous interstate pipeline connections and growing supply and demand dynamics in the surrounding regions, we believe that our location near the Perryville Hub provides us a strategic advantage in securing supplies of natural gas.

Natural gas flows from north to south on the Midla mainline from interconnections with other interstate pipelines to customers and end users. The Midla system consists of the following components:

- the northern portion of the system, including the T-32 lateral;

- the mainline; and
- the southern portion of the system, including interconnections with the MLGT system and other associated laterals.

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. These power plants are peak-load generating facilities that consumed an aggregate average of approximately 33.4 MMcf/d and 26.8 MMcf/d of natural gas for the years ended December 31, 2012 and 2011, respectively. The T-32 lateral is fully subscribed, with approximately 296 MMcf/d of firm transportation capacity under contracts that automatically renew on a year-to-year basis.

The mainline has a design capacity of approximately 198 MMcf/d and consists of approximately 172 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. Average throughput on the Midla mainline for the years ended December 31, 2012 and 2011 was approximately 72.7 MMcf/d and 44.6 MMcf/d, respectively.

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. Natural gas delivered on the southern end of the system is sold under both firm and interruptible transportation contracts with average remaining terms of two years.

MLGT System

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. Average throughput on the MLGT system for the years ended December 31, 2012 and 2011 was approximately 44.5 MMcf/d and 51.9 MMcf/d, respectively.

Other Systems

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. The approximate average throughput for these systems was 9.8 MMcf/d and 10.6 MMcf/d, respectively, for the year ended December 31, 2012 and 10.6 MMcf/d and 13.0 MMcf/d, respectively, for the year ended December 31, 2011. Finally, we also own a number of miscellaneous interconnects and small laterals that are collectively referred to as the SIGCO assets.

Growth Opportunities

In our Transmission segment, we continually seek to increase throughput volumes and volumes under firm transportation contracts on our pipelines. We also seek to identify and evaluate economically attractive organic expansion and asset opportunities that leverage our existing asset footprint and strategic relationships with our customers. Currently, we are evaluating the following growth opportunities:

- the addition of delivery points to the AlaTenn system, which we believe will improve overall system flexibility and allow us to capitalize on possible incremental natural gas demand from various electric utilities on our system who are either in the process of, or are evaluating, switching fuel sources from coal to natural gas;
- the addition of LDC and industrial customers on the AlaTenn system who were historically commercially underserved;
- the addition of new industrial customers on the AlaTenn system that are constructing new facilities to take advantage of the low prices of natural gas in the U.S.;

- the construction of a new pipeline lateral on our Chalmette system to accommodate a potential new facility outside of New Orleans;
- the addition of new pipelines and compression to increase the volume of gas delivered to Natchez, Mississippi for new industrial customers that are developing there; and
- the addition of a new interstate pipeline interconnect on our AlaTenn system that would enhance AlaTenn's access to low cost natural gas supply for its current and potential new customers, further enhancing AlaTenn's competitive position in the region and ultimately increasing throughput volume on the pipeline.

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. Among all of our customers in this segment, the weighted-average remaining life of our firm and interruptible transportation contracts are approximately five years and less than one year, respectively. ExxonMobil, Enbridge Marketing (US) L.P., and Calpine Corporation are the three largest purchasers of natural gas and transmission capacity, respectively, in our Transmission segment and accounted for approximately 50%, 22% and 10%, respectively, of our segment revenue for the year ended December 31, 2012 and approximately 57%, 22% and 8%, respectively, of our segment revenue for the year ended December 31, 2011.

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 and ANR.

In our Transmission segment, we compete with other pipelines that service regional markets, specifically in our Baton Rouge market. An increase in competition could result from new pipeline installations or expansions by 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 and Louisiana Intrastate Gas.

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 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 thorough 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 are certified by the US 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, or 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, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act 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 also 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;
- OSHA Process Safety Management Regulations, which are designed to prevent or minimize the consequences of catastrophic releases 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.

Interstate Natural Gas Pipeline Regulation

Our interstate natural gas transportation systems are subject to the jurisdiction of FERC under the Natural Gas Act of 1938, (“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 which 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, or "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 the FERC 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 which 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 has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring 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, (“EPAct 2005”). Among other matters, the EPAct 2005 amended the NGA to add an anti-manipulation provision which 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 EPAct 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 EPAct 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 EPAct 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, or 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 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” or the “Superfund law”), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to 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, and our Predecessor has in the past owned or leased, 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 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 (intrafacility 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. Other than as described below with respect to our Bazor Ridge and Chatom systems, we believe that we are in substantial compliance with these requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that 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 (“MDEQ”). Under this permit, we are allowed to emit up to a specified level of sulfur dioxide, or SO2, per year.

In the course of preparing our annual MDEQ filing for 2010 as required by our Title V Air Permit, we determined that we underreported to MDEQ the SO2 emissions from the Bazor Ridge plant for 2009 and 2010. Moreover, we discovered that SO2 emission levels during 2009 may have exceeded the threshold that triggers the need for a Prevention of Significant Deterioration (“PSD”), permit under the federal Clean Air Act. No PSD permit has been issued for the Bazor Ridge plant. In addition, we recently determined that certain SO2 emissions during 2009 and 2010 exceeded the reportable quantity threshold under the federal Emergency Planning and Community Right-to-Know Act (“EPCRA”), requiring notification of various governmental authorities. We did not make any such EPCRA notifications. In July 2011, we self-reported these issues to the MDEQ and EPA Region IV. In January 2012, we met with EPA Region IV representatives, and have agreed to a settlement with respect to the EPCRA reporting issue. A Consent Agreement and Final Order was executed, which included a civil penalty of $23,010. After discussion with the MDEQ, in February 2012 we submitted an application to amend our Title V Air Permit to account for these SO_2 emissions. The MDEQ has processed this permit application. In December 2011, EPA Region IV performed an inspection of the plant, and they followed up with an Information Request in May 2012. We have responded to this Information Request and do not anticipate any further action required by the Partnership at this time.

On March 11, 2013, the Environmental Protection Agency issued a Clean Air Act Compliance Order related to an inspection of the Chatom processing plant on May 15, 2012. The order was issued to Quantum Resources Management, LLC, the owner at the time of the inspection. EPA has requested information regarding releases identified during the inspection, including a description of the equipment and repairs that were performed. We will timely respond to this request. At this time, we cannot determine whether EPA may pursue further enforcement related to these releases and cannot predict the amount of any potential fines or penalties.

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.

Spill prevention, control and countermeasure 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 which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews which 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") and including 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.

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.

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: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. 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, 2012, our general partner employed approximately 107 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 good.

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 our IPO offering document 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 June 2012 amended credit facility includes financial covenants and ratios. We may have difficulty maintaining compliance with the financial covenants, 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 June 2012 amended 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 June 2012 amended credit facility could result in a default, which could cause all of our existing indebtedness to become immediately due and payable. We were unable to maintain compliance with consolidated total leverage ratio required by our June 2012 amended credit agreement as it existed prior to the Fourth Amendment during the quarters ended December 31, 2012 and March 31, 2013. On April 15, 2013, we entered into a Fourth Amendment to our June 2012 amended credit agreement that, among other things, modified the maximum permitted consolidated total leverage ratio. The maximum consolidated total leverage ratio permitted by the Fourth Amendment varies by quarter, initially permitting a ratio of 5.90 to 1.00 for the quarter ending June 30, 2013 and then gradually lowering to 4.50 to 1.00 commencing with the quarter ending March 31, 2015. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Our Credit Facility" for more information about the Fourth Amendment and our June 2012 amended credit facility.

We may not have sufficient cash from operations following 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 subordinated 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 unit. 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;
- 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 or 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, 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, 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:
- 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 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.

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. The NYMEX daily settlement price for natural gas for the forward month contract in 2012 ranged from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu. Natural gas prices reached relatively high levels in 2005 and early 2006 and have exhibited significant volatility since then, including a sustained decline beginning in 2008, with the forward month gas futures contracts closing at a seven-year low of $2.32 per MMBtu in January 2012. NGL prices are generally positively correlated to the price of WTI crude oil, which has also exhibited frequent and substantial fluctuations. The NYMEX daily settlement price for WTI crude oil for the forward month contract in 2012 ranged from a high of $109.77 per Bbl to a low of $77.69 per Bbl. Crude oil prices reached historically high levels in July 2008, hitting a peak of $145.29 per Bbl, and have demonstrated substantial volatility since then, with the forward month crude oil futures contracts ranging from $33.87 per Bbl in December 2008 to above $113.93 per Bbl in April 2011.

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 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 and NGLs 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, 2012 and 2011, percent-of-proceeds arrangements accounted for approximately 51.4% and 41.3%, respectively, of our gross margin, or 69.8% and 58.8%, respectively, of the segment gross margin in our Gathering and Processing segment.

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.

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.

Our hedging activities may not be effective in reducing our direct exposure to commodity price risk and the variability of our cash flows 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 December 2013. 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. 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.

We are a relatively small enterprise, and our management has limited history with our assets and limited experience in managing our business as a publicly traded partnership. 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 will 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 business as a publicly traded partnership and has managed our business and assets for less than four years. 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 such 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 currently have a limited accounting staff, and if we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results timely and accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

We are subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended (“Exchange Act”). Effective internal controls are necessary for us to provide reliable and timely financial reports, prevent fraud and to operate successfully as a publicly traded partnership. We prepare our consolidated financial statements in accordance with GAAP, but our internal accounting controls may not meet all standards applicable to companies with publicly traded securities. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 requires us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting (an independent attestation was not required for 2012 due to our non-accelerated filer status). We have implemented an internal control environment to comply with Section 404 for our fiscal year ending December 31, 2012. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations.

We currently have limited accounting personnel, and while we continue to evaluate the adequacy of our accounting personnel staffing level and other matters related to our internal controls over financial reporting, we cannot predict the outcome 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, in addition to our limited accounting personnel and management resources, 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. 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 or more of these customers could adversely affect our ability to make distributions to you.

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 or 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 any of 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.

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 the Tennessee Gas Pipeline, or TGP, 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 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, 2012, our Gathering and Processing segment derived 40%, 12% and 11% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Shell, respectively. For the year ended December 31, 2011, our Gathering and Processing segment derived 55%, 16% and 9% of its revenue from ConocoPhillips, Enbridge Marketing (US) L.P., and Dow Hydrocarbons and Resources, respectively. Additionally, ExxonMobil, Enbridge Marketing (US) L.P., and Calpine Corporation are the three largest purchasers of natural gas and transmission capacity, respectively, in our Transmission segment and accounted for approximately 50%, 22% and 10%, respectively, of our segment revenue for the year ended December 31, 2012 and approximately 57%, 22% and 8%, respectively, of our segment revenue for the year ended December 31, 2011.
Some of our customers 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 could have a material adverse effect on our revenue, gross margin and cash flows and our ability to make cash distributions to our unitholders.
Our gathering, processing and transportation 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. 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.
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 or transportation 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.
We purchased our assets from Enbridge in November 2009. Significant portions of the pipeline systems that we purchased have been in service for many decades. In addition, our executive management team was hired shortly before that purchase and, consequently, has a limited history of operating our 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 Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the U.S. Department of Transportation ("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 $0.1 million during 2013 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.

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 will 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.

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. 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 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.

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.

For example, in April 2010, there was a rupture in our Bazor Ridge gathering pipeline which gathers natural gas high in hydrogen sulfide content which resulted in an extended shut-down of a significant portion of that system until the pipeline could be inspected and repaired. The affected portion of the line is the one that gathered the most significant volumes of gas on this system and delivered it to our Bazor Ridge plant, and we were required to curtail a portion of this flow volume until we built a new bypass pipeline, the Winchester Lateral, connecting this production, as well as potential new production, to the Bazor Ridge plant. The affected section of line was fully shut down for approximately 25 days and, until our Winchester Lateral was completed approximately 177 days later, we were able to gather only

approximately 70% of pre-rupture flow volume. The Winchester Lateral cost $3.9 million to construct and the repairs to, and testing of the affected sections of pipe cost approximately $0.5 million.
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 Federal Energy Regulatory Commission ("FERC"), under the Natural Gas Act of 1938 ("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 and 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 Energy Policy Act of 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. The FERC also requires interstate pipelines to adhere to its rules regarding the filing and approval of transportation agreements that include provisions which differ from the transportation agreements included in their FERC gas tariff. We are conducting a review of the transportation agreements entered into by our predecessor to determine whether, and to what extent, any of our transportation agreements include such provisions. 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 unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 ("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. Because proposed rate increases are procedurally complicated, we may have a significant period of time during which our gross margin from such FERC-regulated systems may be materially less than we have historically obtained.

Our new pipeline and related assets acquired through High Point Infrastructure Partners are subject to additional orders from the FERC.

The pipeline and related assets that we acquired from High Point on April 15, 2013 are owned by two of our subsidiaries, High Point Gas Transmission, LLC (“HPGT”) and High Point Gas Gathering, LLC (“HPGG”). In an order issued in June 2012, the FERC approved the abandonment of these mainly offshore assets by Southern Natural Gas Company, L.L.C (“Southern Natural”) to allow for their transfer to HPGT. The FERC determined that some of these assets constitute gathering facilities that are generally exempt from FERC regulation under the Natural Gas Act. FERC's June 21, 2012 order also authorizes HPGT to own and operate the jurisdictional assets, specifically the assets that are used for interstate transmission of natural gas. Following its acquisition of the assets from Southern Natural, HPGT transferred the exempt gathering assets to HPGG. Several shippers who protested Southern Natural's application to abandon these assets and HPGT's application to own and operate these assets have sought rehearing of the FERC's June 2012 order approving the applications. The shippers who are gas producers whose production is gathered by these assets are complaining to the FERC that the transfer should not have been authorized because the effect has been to result in additional charges for the use of the facilities to deliver gas to Southern Natural at a point onshore. They also are alleging that Southern Natural had no FERC authorization to transfer the exempt gathering facilities to HPGG, but only to HPGT.

Notwithstanding the rehearing request, the FERC's June 2012 order is fully effective. Although the producers might have asked FERC to stay its order, they did not do so. As authorized by the June 2012 order, Southern Natural abandoned the facilities and transferred them to HPGT, which then transferred the exempt gathering facilities to HPGG. (Southern Natural did not transfer the facilities directly to HPGT.) While the shipper's request for rehearing asked FERC to disapprove the original abandonment by Southern Natural, the shippers did not seek any other relief as to HPGT's authority to own and operate the assets or FERC's authority to unwind the transfers at that time. Subsequently, after the statutory deadline for such requests, shippers sought to void HPGT's authorization to own and operate the assets and to unwind the transaction; however, the Company believes these requests are time-barred. The shipper's requests for rehearing of the June 2012 order and subsequent requests remain pending. It is not known whether FERC will change its original decision, or whether the shippers will appeal the FERC's order to the courts if their requests are denied. While we consider any adverse outcome unlikely, an adverse result could have a materially adverse effect on our financial condition.

In a separate proceeding, HPGT filed with FERC initial rates for interstate gas transportation service in compliance with the FERC's June 2012 order. In an order issued in September 2012, the FERC allowed HPGT to collect its proposed rates starting as of November 1, 2012, the date that HPGT acquired the assets from Southern Natural; however the collection of rates is “subject to refund” and a final ruling by the FERC on the rates and on the requests for rehearing. The shippers have protested HPGT's initial rates, alleging that they are excessive because, among other reasons, HPGT did not allocate enough costs to the gathering service rates. As a result of information requests from the FERC's staff, HPGT has filed additional rate calculations using different allocation methods as requested. The shipper protests remain pending. We believe that our initial rates are just and reasonable, however, should the FERC determine that the shippers are owed a refund, it could have a materially adverse effect on our financial condition.

A standard requirement in the June 2012 FERC order is that HPGT file, in three years, a cost and revenue study based on a recent 12-month period. The FERC will review the study and determine whether it believes HPGT is collecting excessive revenue. Although the results of the cost/revenue study are uncertain at this early stage, if the FERC were to conclude that HPGT had been collecting excess revenue, it could initiate a rate proceeding to require HPGT to determine whether its rates should be lowered prospectively. If the initial rates are determined to be too low and not sufficient to enable HPGT to cover its costs, HPGT would have the option to file at any time for a prospective rate increase. Although we believe that HPGT's rates are just and reasonable, we are unable to predict the likelihood that the FERC will conclude, based on HPGT's filing in three years, that HPGT's rates resulted in the collection of excess revenue and that HPGT's rates should be reduced prospectively, and if such efforts are successful the amount of any such rate reduction.

The application of certain FERC policy statements could affect the rate of return on our equity we are allowed to recover through rates and the amount of any allowance (if any) 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, the FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of these companies transferring gathering facilities to federally 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.

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 Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or the "Superfund law"), 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 Water Pollution Control Act ("Clean Water Act"), and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the federal Oil Pollution Act ("OPA"), and analogous state laws that establish strict liability for releases of oil into waters of the United States;
- the federal Resource Conservation and Recovery Act ("RCRA"), and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities;
- the Endangered Species Act ("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 U.S. Environmental Protection Agency ("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. For example, with respect to our Bazor Ridge system, in the course of preparing our annual MDEQ filing for 2010 as required by our Title V Air Permit, we determined that we underreported to MDEQ the SO2 emissions from the Bazor Ridge plant for 2009 and 2010. Moreover, we discovered that SO2 emission levels during 2009 may have exceeded the threshold that triggers the need for a Prevention of Significant Deterioration ("PSD"), permit under the federal Clean Air Act. No PSD permit has been issued for the Bazor Ridge plant. In addition, we recently determined that certain SO2 emissions during 2009 and 2010 exceeded the reportable quantity threshold under the federal Emergency Planning and Community Right-to-Know Act ("EPCRA"), requiring notification of various governmental authorities. We did not make any such EPCRA notifications. In July 2011, we self-reported these issues to the MDEQ and EPA Region IV. In January 2012, we met with EPA Region IV representatives, and have agreed to a settlement with respect to the EPCRA reporting issue. A Consent Agreement and Final Order was executed, which included a civil penalty of $23,010. After discussion with the MDEQ, in February 2012 we submitted an application to amend our Title V Air Permit to account for these SO_2 emissions. The MDEQ has processed this permit application. In December 2011, EPA Region IV performed an inspection of the plant, and they followed up with an Information Request in May 2012. We have responded to this Information Request and do not anticipate any further action required by the Partnership at this time.

On March 11, 2013, the Environmental Protection Agency issued a Clean Air Act Compliance Order related to an inspection of the Chatom processing plant on May 15, 2012. The order was issued to Quantum Resources Management, LLC, the owner at the time of the inspection. EPA has requested information regarding releases identified during the inspection, including a description of the equipment and repairs that were performed. We will timely respond to this request. At this time, we cannot determine whether EPA may pursue further enforcement related to these releases and cannot predict the amount of any potential fines or penalties.

Please read "Business — Environmental Matters — Air Emissions" for more information about these matters. 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.

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. 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. We may not be able to recover all or any of these costs from insurance. Please read "Business — Environmental Matters" for more information.

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.”

Climate change legislation, regulatory initiatives and litigation 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 greenhouse gas

(“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.

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 beginning in 2011. 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 by March 2012 for emissions during 2011 and annually thereafter. We filed emission reports for our Bazor Ridge and Chatom systems in March 2012. In 2010, the EPA also 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.

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, EPA received petitions for reconsideration of certain aspects of the standards. On April 12, 2013, EPA published proposed updates to the NSPS Section OOOO storage tank requirements.

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

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 Pipeline and Hazardous Materials Safety Administration ("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. We believe that this rule does not apply to any of our pipelines. While 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. 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.

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 and increase the working capital requirements to conduct these activities.

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

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

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

We 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. 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.

Restrictions in our June 2012 amended credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and value of our common units.

Our June 2012 amended credit facility limits our ability to, among other things:

- incur additional debt;
- make distributions on or redeem or repurchase units;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and

- transfer or otherwise dispose of assets.

Our June 2012 amended credit facility also contains covenants requiring us to maintain certain financial ratios. The provisions of our June 2012 amended credit facility affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our June 2012 amended credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

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.

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.

We currently have a small management team, and 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. 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 competition for these persons in the midstream natural gas industry is intense. 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 of our general partner. 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 affect adversely 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, 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.

The amount of cash we have available for distribution to holders of our common and subordinated 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.

Risks Inherent in an Investment in Us

HighPoint Infrastructure Partners, LLC, an affiliate of ArcLight Captial Partners, and AIM Midstream Holdings directly own and control our general partner, which has sole responsibility for conducting our business and managing our operations. HighPoint Infrastructure Partners, 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.

HighPoint Infrastructure Partners and AIM Midstream Holdings own and control our general partner and appoints all of the officers and directors of our general partner, some of whom are also officers of HighPoint Infrastructure Partners and AIM Midstream Holdings. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owners, HighPoint Infrastructure Partners and AIM Midstream Holdings. Conflicts of interest may arise between HighPoint Infrastructure Partners 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 HighPoint Infrastructure Partners 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 HighPoint Infrastructure Partners and 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 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 subordinated 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 subordinated units, to make incentive distributions or to accelerate the expiration of the 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 subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;
- our general partner controls the enforcement of the obligations that it and its affiliates owe to us;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue 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.

HighPoint Infrastructure Partners 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.

HighPoint Infrastructure Partners 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, HighPoint Infrastructure Partners 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 HighPoint Infrastructure Partners 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 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."

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 common and subordinated 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 in order 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 June 2012 amended 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 holders of our common and subordinated 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 and subordinated 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 when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, 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. Please read "Provisions of Our Partnership Agreement Relating to Cash

Distributions — General Partner’s Right to Reset Incentive Distribution Levels.”

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 High Point Infrastructure Partners. 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.

The unitholders currently are unable to remove our general partner without its consent because our general partner and its affiliates owns 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. HighPoint Infrastructure Partners own 69% of outstanding limited partner units and AIM Midstream Holdings who owns 5% of our outstanding limited partner units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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

Unitholders' voting rights are further restricted by 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 HighPoint Infrastructure Partners and AIM Midstream Holdings 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 a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by 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.

HighPoint Infrastructure Partners 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.

AIM Midstream Holdings currently holds an aggregate of 725,120 common units and HighPoint Infrastructure Partners holds 4,526,066 subordinated units and 5,142,857 preferred units. All of the subordinated units will convert into common units at the end of the subordination period. The preferred units are convertible into common units at the election of High Point Infrastructure partners at any time after January 1, 2014. 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. AIM Midstream Holdings owns approximately 16.0% of our outstanding common units. HighPoint Infrastructure Partners owns 4,526,066 subordinated units and 5,142,857 preferred units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), HighPoint Infrastructure Partners will own approximately 69% of our outstanding common units assuming our preferred units are converted into common units on a one-for-one basis, AIM Midstream Holdings would own 5% of our outstanding 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.
Tax Risks to Common Unitholders
Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our 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 Internal Revenue Service (“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. 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 35.0%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate distributions (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through

to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such a tax on us by Texas, and if applicable by any other state, will reduce the cash available for distribution to you. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, 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. Recently, members of the U.S. Congress have considered substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships, which, if enacted, may or may not be applied retroactively. Although we are unable to predict whether any of these changes or any other proposals will ultimately be enacted, any such changes could negatively impact the value of an investment in our common units.

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

Because a unitholder will be treated as a partner to whom we will allocate taxable income 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. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from that income.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this Annual Report 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 and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel’s conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

If you sell your common units, you will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized on any sale of your 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 you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read “Material Federal Income Tax Consequences — Disposition of Common Units — Recognition of Gain or Loss” for a further discussion of the foregoing.

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

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

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. Our counsel is unable to opine as to the validity of such filing positions. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read "Material Federal Income Tax Consequences — Tax Consequences of Unit Ownership — Section 754 Election" for a further discussion of the effect of the depreciation and amortization positions we have adopted.

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 our unitholders.

We will 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. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Andrews Kurth LLP has not rendered an opinion with respect to whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations. Please read "Material Federal Income Tax Consequences — Disposition of Common Units — Allocations Between Transferors and Transferees."

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for federal income 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, he may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may 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; therefore, our 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 consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We will adopt certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

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

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

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for 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 recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years. Please read "Material Federal Income Tax Consequences — Disposition of Common Units — Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

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

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

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state 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 in the future. 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.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

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 1614 15th Street, Suite 300, Denver, CO 80202 and our telephone number is 720-457-6060.

Item 3. Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business.

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 the common units, as reported by the New York Stock Exchange ("NYSE") for each quarter since our IPO together with distributions paid subsequent to each quarter for that quarter through December 31, 2012:

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2012				
High Price	$19.44	$21.75	$22.77	$22.80
Low Price	$13.64	$18.65	$18.90	$18.89
Distribution per common unit	$0.4325	$0.4325	$0.4325	$0.4325
2011				
High Price	$19.57	$23.37	—	—
Low Price	$16.80	$16.00	—	—
Distribution per common unit	$0.4325	$0.2690	—	—

As of March 13, 2013, there were 12 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 4,526,066 subordinated units and 185,451 general partner units, for which there is no established trading market. All of the subordinated units and general partner units are held by affiliates of our general partner. Our general partner and its affiliates receive quarterly distributions on these units only after sufficient funds have been paid to the common units.

Overview of Distributions

During the past two fiscal years, our unitholders have received distributions from us on a pro rata basis. Holders of our previously outstanding units received their pro rata share of distributions as follows:

(in thousands)	
November 2012	$3,939
August 2012	3,939
May 2012	3,940
February 2012	3,930
November 2011 (b)	2,485
August 2011 (a)	33,723
May 2011	3,674
February 2011	3,664

(a) In August 2011 we made a special distribution of $33.7 million in connection with our IPO to AIM Midstream Holdings, LLC, participants in our LTIP holding common units and our general partner.

(b) Represents a pro-rated distribution of $0.2690 per unit for the period from August 2, 2011 through September 30, 2011.

On January 25, 2013, we announced a distribution of $0.4325 per unit payable on February 14, 2013 to unitholders of record on February 7, 2013.

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. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax.
The following table sets forth the number of common, subordinated common and general partner units at December 31, 2012:

	December 31,	
	2012	2011
	(in thousands)	
Limited partner common units	4,639	4,561
Limited partner subordinated units	4,526	4,526
General partner units	185	185

Our general partner's initial 2.0% interest in distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2.0% general partner interest.
The subordination period generally will end and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $1.65 on each outstanding common and subordinated unit and the corresponding distribution on our general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after September 30, 2014. The subordination period will automatically terminate and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $2.475 (150% of the annualized minimum quarterly distribution) on each outstanding common and subordinated unit and the corresponding distributions on our general partner's 2.0% interest and incentive distribution rights for any four consecutive quarter period ending on or after September 30, 2012; provided that we have paid at least the minimum quarterly distribution from operating surplus on each outstanding common unit and subordinated unit and the corresponding distribution on our general partner's 2.0% interest for each quarter in that four-quarter period.
If we do not pay the minimum quarterly distribution on our common units, our subordinated unitholders will not be entitled to receive such payments in the future except in some circumstances during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units and the corresponding distributions on our general partner's 2.0% interest, we will use this excess available cash to pay any distribution arrearages on the common units related to prior quarters before any cash distribution is made to holders of the subordinated units.
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 of February, May, August and November to holders of record on or about the 1st 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.
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 an LTIP 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 LTIP. On July 11, 2012, the board of directors of our general partner adopted a second amended and restated long-term incentive plan that effectively increased available awards by 871,750 units. At December 31, 2012, 2011 and 2010, there were 920,193, 54,827 and 62,246 units, respectively, available for future grant under the LTIP giving retroactive treatment to the reverse unit split described in Note 13

“Partners’ Capital”.

Recent Sales of Unregistered Units

None

Repurchase of Equity by American Midstream Partners, LP

None

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, historical combined Predecessor financial statements and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those financial statements and notes, which for the years 2012, 2011, and 2010 begin on F-1 to this Annual Report.

We acquired the Predecessor assets effective November 1, 2009. During the period from our inception, on August 20, 2009, to October 31, 2009, we had no operations although we incurred certain fees and expenses of approximately $6.4 million associated with our formation and the acquisition of our assets from Enbridge, which are reflected in the "Transaction costs" line item of our consolidated financial data for the period from August 20, 2009 through December 31, 2009.

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

	American Midstream Partners, LP and Subsidiaries (Successor)				American Midstream Partners Predecessor	
	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from August 20, 2009 (Inception Date) to 2009 December 31, 2009	10 Months Ended October 31, 2009	Year Ended December 31, 2008
	(in thousands, except per unit and operating data)					
Statement of Operations Data:						
Revenue	$209,594	$248,282	$212,248	$ 32,833	$ 143,132	$ 366,348
Realized gain (loss) in early termination of commodity derivatives	—	(2,998)	—	—	—	—
Unrealized gain (loss) on commodity derivatives	992	(541)	(308)	—	—	—
Total revenue	210,586	244,743	211,940	32,833	143,132	366,348
Operating expenses:						
Purchases of natural gas, NGLs and condensate	155,667	202,403	173,821	26,593	113,227	323,205
Direct operating expenses	18,202	12,856	12,187	1,594	10,331	13,423
Selling, general and administrative expenses	14,309	10,794	7,120	1,196	8,577	8,618
Advisory services agreement termination fee	—	2,500	—	—	—	—
Transaction expenses	—	282	303	6,404	—	—
Equity compensation expense(a)	1,783	3,357	1,734	150	—	—
Depreciation expense	21,414	20,705	20,013	2,978	12,630	13,481
Total operating expenses	211,375	252,897	215,178	38,915	144,765	358,727
Gain (loss) on acquisition of assets	—	565	—	—	—	—
	(1,021)	—	—	—	—	—

Gain (loss) on involuntary conversion of property, plant and equipment						
Gain (loss) on sale of assets, net	128	399	—	—	—	—

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Operating income (loss)	(1,682)	(7,190)	(3,238)	(6,082)	(1,633)	7,621
Other income (expense)						
Interest expense	(4,570)	(4,508)	(5,406)	(910)	(3,728)	(5,747)
Other income (expense)	—	—	—	—	24	854
Net income (loss)	(6,252)	(11,698)	(8,644)	$(6,992)	$(5,337)	$2,728
Net income (loss) attributable to non-controlling interests	256	—	—	—	—	—
Net income (loss) attributable to the Partnership	(6,508)	(11,698)	(8,644)	(6,992)	(5,337)	2,728
General partner’s interest in net income (loss)	(129)	(233)	(173)	(140)		
Limited partners’ interest in net income (loss)	$(6,379)	$(11,465)	$(8,471)	$(6,852)		
Limited partners’ net income (loss) per unit	$(0.70)	$(1.64)	$(1.66)	$(3.13)		
Weighted average number of units used in computation of limited partners’ net income (loss) per unit (h)	9,113	6,997	5,099	2,187		
Statement of Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$18,348	$10,432	$13,791	$(6,531)	$14,589	$18,155
Investing activities	(62,427)	(41,744)	(10,268)	(151,976)	(853)	(10,486)
Financing activities	43,784	32,120	(4,609)	159,656	(14,088)	(7,929)
Other Financial Data:						
Adjusted EBITDA(b)	$18,277	$21,041	$18,263	$3,450	$11,021	$21,956
Distributable cash flow(f)	9,588	13,212	9,549	1,913	—	—
Distributable cash flow per weighted average unit outstanding(g)	1.05	1.85	1.84	0.86	—	—
Gross margin(c)	50,554	45,879	38,119	6,240	29,905	43,143
Segment gross margin:						
Gathering and Processing	37,241	32,142	24,595	3,698	20,024	27,354
Transmission	13,313	13,737	13,524	2,542	9,881	15,789
Balance Sheet Data (At Period End):						
Cash and cash equivalents	$576	$871	$63	$1,149	$149	$421
Accounts receivable and unbilled revenue	23,470	20,963	22,850	19,776	8,756	9,532
Property, plant and equipment, net	223,819	170,231	146,808	146,226	205,126	216,903
Total assets	256,696	199,551	173,229	174,470	250,162	277,242
Total debt (current and long term)(d)	128,285	66,270	56,370	61,000	—	60,000
Operating Data:						
Gathering and processing Segment:						
Throughput (MMcf/d)	299.3	250.9	175.6	169.7	211.8	179.2

Plant inlet volume (MMcf/d)(e)	116.1	36.7	9.9	11.4	11.7	12.5
Gross NGL production (Mgal/d)(e)	49.9	54.5	34.1	38.2	39.3	40.2
Gross condensate production (Mgal/d)(e)	22.6	6.8	—	—	—	—
Transmission segment:						
Throughput (MMcf/d)	398.5	381.1	350.2	381.3	357.6	336.2
Firm transportation - capacity reservation (MMcf/d)	703.6	702.2	677.6	701.0	613.2	627.3
Interruptible transportation throughput (MMcf/d)	86.6	69.0	80.9	118.0	121.0	141.6

(a) Represents cash and non-cash costs related to our LTIP. Of these amounts, $1.8 million, $1.6 million, $1.2 million and $0.2 million, for the years ended December 31, 2012, 2011, 2010 and the period ended December 31, 2009, respectively, were non-cash expenses.

(b) For a definition of adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read “Selected Historical Financial and Operating Data — Non-GAAP Financial Measures,” and for a discussion of how we use adjusted EBITDA to evaluate our operating performance, please read “— How We Evaluate Our Operations.”

(c) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, Note 19 to our audited consolidated financial statements included elsewhere in this Annual Report and for a discussion of how we use gross margin to evaluate our operating performance, please read “— How We Evaluate Our Operations.”

(d) Excludes Predecessor Note payable to Enbridge Midcoast Limited Holdings, L.L.C. of $39.3 million as of December 31, 2008.

(e) Excludes volumes and gross production under our elective processing arrangements. For a description of our elective processing arrangements, please read “Business — Gathering and Processing Segment — Gloria System.”

(f) For a definition of distributable cash flow and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read “Selected Historical Financial and Operating Data — Non-GAAP Financial Measures,” and for a discussion of how we use distributable cash flow to evaluate our operating performance, please read “— How We Evaluate Our Operations.”

(g) For a definition of distributable cash flow and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read “Selected Historical Financial and Operating Data — Non-GAAP Financial Measures,” and for a discussion of how we use distributable cash flow to evaluate our operating performance, please read “— How We Evaluate Our Operations.”

(h) Includes unvested phantom units with DERs, which are considered participating securities, of 205,864 and 175,236 as of December 31, 2010 and 2009, respectively . The DER’s were eliminated on June 9, 2011. There were no such unvested phantom units with DERs at December 31, 2011 or subsequent. The unit count also gives effect to the reverse unit split as described in Note 13, “Partners’ Capital” of our audited consolidated financial statements included in this Annual Report beginning on page F-1.

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 Regarding Forward-Looking Statements.”

Overview

We are a growth-oriented Delaware limited partnership that was formed by affiliates of AIM in August 2009 to own, operate, develop and acquire a diversified portfolio of natural gas midstream energy assets. We are engaged in the business of gathering, treating, processing, fractionating and transporting natural gas through our ownership and operation of ten gathering systems, four processing facilities, two interstate pipelines and four intrastate pipelines. We also own a 50% undivided, non-operating interest in a processing plant located in southern Louisiana. Our primary assets, which are strategically located in Alabama, Louisiana, Mississippi, and Texas, provide critical infrastructure that links producers and suppliers of natural gas to diverse natural gas markets, including various interstate and intrastate pipelines, as well as utility, industrial and other commercial customers. We currently operate approximately 1,400 miles of pipelines that gather and transport over 600 MMcf/d of natural gas.

Significant financial highlights during the year ended December 31, 2012, include the following:

- Our distributable cash flow for the year ended December 31, 2012 was $9.6 million. We distributed $16.1 million to our unitholders or $1.73 per unit.
- For the year ended December 31, 2012, gross margin increased to $50.6 million or 10.2% compared to the same period in 2011;
- The Partnership acquired an 87.4% interest in the Chatom processing and fractionation plant and associated gathering infrastructure (the "Chatom system") from affiliates of Quantum Resources Management, LLC, effective July 1, 2012, for approximately $51.4 million; and
- The Partnership amended its August 2011 credit facility to increase the borrowing capacity from $100 million to $200 million with a syndicate of eight banks led by Bank of America, N.A., as Administrative Agent, Collateral Agent, L/C Issuer and Lender.

Significant operational highlights and challenges during the year ended December 31, 2012, include the following:

- Throughput attributable to American Midstream Partners, LP totaled 697.8 MMcf/d for the year, representing a 10.4% increase compared to the same period in 2011;
- Certain assets were impacted by Hurricane Isaac, the negative financial impact for which was approximately $3.0 million. A portion of this amount related to foregone cash flows resulting from production curtailments immediately following the hurricane, and the remainder resulted from costs incurred to repair the damaged assets during the third and fourth quarters of 2012. The Partnership is insured for named windstorms on the affected assets after a $1.0 million deductible. The gathering and processing volumes associated with the assets that were damaged during Hurricane Isaac have returned to pre-hurricane levels;
- The Partnership completed a scheduled turnaround of its Bazor Ridge processing plant in eastern Mississippi. The turnaround took longer than anticipated as a result of unscheduled repairs and upgrades that slowed the turnaround process but are expected to deliver long-term, improved efficiencies at the plant. The negative financial impact of the turnaround in the fourth quarter was approximately $1.1 million; and
- The Partnership saw a decline in volumes on one of its offshore pipeline systems during the third and fourth quarters of 2012 as a result of a producer's work on one of its platforms. The Partnership continues to work with this producer to negotiate the return of incremental volumes to the offshore pipeline system, although the contract terms may change for the incremental volumes going forward and a change in contract terms may have a material negative impact on financial results. While the Partnership expects the incremental volumes to return during the first half of 2013, the reduced volumes during the third and fourth quarters of 2012 resulted in a negative financial impact of approximately $2.0 million.

Our Operations

We manage our business and analyze and report our results of operations through two 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 local distribution companies (“LDCs”), utilities and industrial, commercial and power generation customers.

Gathering and Processing Segment

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 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. By entering into back-to-back purchases and sales of natural gas, 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 and NGLs 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 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 87.4% undivided interest in the Chatom system pursuant to 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 primarily by capacity reservation fees from firm transportation contracts and, to a lesser extent, 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.

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Contract Mix

Set forth below is a table summarizing our average contract mix for the years ended December 31, 2012 and 2011:

	For the Year Ended December 31, 2012			For the Year Ended December 31, 2011		
	Segment Gross Margin (in millions)	Percent of Segment Gross Margin		Segment Gross Margin (in millions)	Percent of Segment Gross Margin	
Gathering and Processing						
Fee based	$8.7	23.6	%	$9.3	28.6	%
Fixed Margin	2.5	6.6	%	4.1	12.6	%
Percent-of-Proceeds	26.0	69.8	%	19.1	58.8	%
Total	$37.2	100.0	%	$32.5	100.0	%
Transmission						
Firm transportation	$10.8	81.2	%	$10.4	75.9	%
Interruptible transportation	1.9	14.3	%	2.1	15.3	%
Fixed margin	0.6	4.5	%	1.2	8.8	%
Total	$13.3	100.0	%	$13.7	100.0	%

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 and distributable cash flow 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 capacity reservation fees, as opposed to the actual 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.

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. 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

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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.

Effective January 1, 2011, we changed our gross margin and segment gross margin measure to exclude unrealized mark-to-market adjustments related to our commodity derivatives. For the year ended December 31, 2011, $0.5 million of unrealized losses was excluded from gross margin and the Gathering and Processing segment gross margin.

Effective April 1, 2011, we changed our gross margin and segment gross margin measure to exclude realized gains and losses associated with the early termination of commodity derivative contracts. For the year ended December 31, 2011, $3.0 million in such realized losses was excluded from gross margin and the Gathering and Processing segment gross margin.

Effective October 1, 2012, we changed our segment gross margin measure to exclude construction, operating and maintenance agreement (“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 and selected charges that are unusual or non-recurring, 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 non-recurring. The GAAP measure most directly comparable to adjusted EBITDA is net income.

We changed our calculation of adjusted EBITDA for 2011 to include the straight-line amortization of commodity put premiums over the life of the associated commodity put contracts. This is necessary as all unrealized commodity gains and losses, by definition, are excluded in calculating adjusted EBITDA and such premium costs would only be included in the calculation of adjusted EBITDA at the expiration of the put contract. We believe this treatment better reflects the allocation of commodity put premium costs over the benefit period of the commodity put contract. Commodity put premium amortization included in the calculation of adjusted EBITDA was $0.4 million for the year ended December 31, 2011. Further we made a change to the calculation to exclude COMA income from adjusted EBITDA. COMA income excluded from adjusted EBITDA for the year ended December 31, 2011 was $0.9 million.

Distributable Cash Flow

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder). Distributable cash flow will not reflect changes in working capital balances.

We define distributable cash flow as adjusted EBITDA plus interest income, less cash paid for interest expense, normalized integrity management costs and normalized maintenance capital expenditures. The GAAP measure most directly comparable to distributable cash flow is net cash flows from operating activities.

Note About Non-GAAP Financial Measures

Gross margin, adjusted EBITDA and distributable cash flows are all 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, adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin, adjusted EBITDA and distributable cash flow 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.

For a reconciliation of segment gross margin to net income, its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 19 to our audited consolidated financial statements included in this Form 10-K.

The following tables reconcile the non-GAAP financial measures, adjusted EBITDA and distributable cash flow used by management to their most directly comparable GAAP measures:

	For the Year Ended December 31, 2012	2011	2010
	(in thousands)		
Reconciliation of Adjusted EBITDA to Net Income (Loss)			
Net income (loss) attributable to the Partnership	$(6,508)	$(11,698)	$(8,644)
Add:			
Depreciation and accretion expense	21,414	20,705	20,013
Interest expense	3,875	4,508	5,406
Debt issuance costs	1,564	—	—
Realized loss on early termination of commodity derivatives	—	2,998	—
Realized loss on commodity put purchase costs	—	308	—
Unrealized (gain) loss on commodity derivatives	(992)	541	—
Non-cash equity compensation expense	1,783	1,607	1,185
Advisory services agreement termination fee	—	2,500	—
Special distribution to holders of LTIP phantom units	—	1,624	—
Transaction expenses	—	282	303
Deduct:			
COMA income	3,373	879	—
Straight-line amortization of put costs (1)	291	409	—
OPEB plan net periodic benefit (cost)	88	82	—
Gain (loss) on acquisition of assets	—	565	—
Gain (loss) on involuntary conversion of property, plant and equipment	(1,021)	—	—
Gain (loss) on sale of assets, net	128	399	—
Adjusted EBITDA	$18,277	$21,041	$18,263
Deduct:			
Cash interest expense (2)	3,854	3,246	4,591
Normalized maintenance capital (3)	3,828	3,083	2,623
Normalized integrity management (4)	1,007	1,500	1,500
Distributable Cash Flow	$9,588	$13,212	$9,549

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

(2) Excludes amortization of debt issuance costs and mark-to-market adjustments related to interest rate derivatives.

(3) Amounts noted represent estimated annual maintenance capital expenditures of $3.8 million for the year ended December 31, 2012 which is what we expect to be required to maintain our assets over the long term.

(4) Amounts noted represent average estimated integrity management costs over the seven year mandatory testing cycle net of integrity management costs that are expensed in Selling, general and administrative expenses.

Items Affecting the Comparability of Our Financial Results

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

- After our initial public offering, we began incurring incremental general and administrative expenses attributable to operating as a publicly traded partnership, such as expenses associated with annual and quarterly SEC reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; director and officer liability insurance costs; and director compensation.
- In November 2010, we completed the construction of the Winchester lateral into our Bazor Ridge processing plant. Since its completion, the lateral has provided approximately 4,000 MMcf/d of incremental gas into the Bazor Ridge

plant.

- In December 2010, we completed an interconnect between our Lafitte pipeline and a pipeline on the TGP interstate system. This interconnect enables us to purchase natural gas from producers on the TGP system and deliver it to the Alliance Refinery

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and the Toca processing plant, which will enable us to process substantially more natural gas under our elective processing arrangements.

- On December 1, 2011, we acquired a 50% undivided interest in the Burns Point Plant from Marathon Oil Company for total cash consideration of $35.5 million. No liabilities of the Seller were assumed. The purchase was effective November 1, 2011.
- Effective July 1, 2012, we acquired an 87.4% undivided interest in the Chatom processing and fractionation plant and associated gathering infrastructure (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.

General Trends and Outlook

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.

Outlook

Prior to 2012, the United States and other industrialized countries experienced a significant economic downturn that led to a decline in worldwide energy demand. North American oil and natural gas supply was increasing as a result of the rise in domestic unconventional production. The combination of lower energy demand due to the economic downturn and higher North American oil and natural gas supply resulted in significant declines in oil, NGL and natural gas prices. While oil and NGL prices began to increase steadily during 2011, natural gas prices remained depressed and volatile throughout 2012 due to a continued increase in natural gas supply despite weaker offsetting demand growth. The outlook for a worldwide economic recovery in 2013 remains uncertain, and the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, we expect natural gas prices to remain relatively low in the near term.

Notwithstanding the ongoing volatility in commodity prices, there has been a recent resurgence in the level of acquisition and divestiture activity in the midstream energy industry and we expect that trend to continue. In particular, we believe that opportunities to acquire midstream energy assets from third parties that fulfill our strategic objectives will continue to arise in the foreseeable future.

Supply and Demand Outlook for Natural Gas and Oil

Natural gas and oil continue to be critical components of energy consumption in the United States. According to the U.S. Energy Information Administration, or EIA, annual consumption of natural gas in the U.S. was approximately 25.4 trillion cubic feet, or Tcf, in 2012, compared to approximately 24.4 Tcf in 2011, representing an increase of approximately 4.1%. Domestic production of natural gas grew from approximately 24.0 Tcf in 2011 to approximately 25.3 Tcf in 2012, or an 5.4% increase. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States, representing approximately 63.9% of the total natural gas consumed in the United States during 2012. In particular, based on a report by the EIA, industrial natural gas demand is expected to grow from 6.1 Tcf in 2009 to 8.2 Tcf in 2020 as a result of an expected recovery in industrial production.

According to the EIA, domestic crude oil production was approximately 6.4 million barrels per day, or MMBbl/d, in 2012, compared to approximately 5.7 MMBbl/d in 2011, representing an increase of approximately 12.3%. Domestic crude oil production is expected to continue to increase over time primarily due to improvements in technology that have enabled U.S. onshore producers to economically extract sources of supply, such as secondary and tertiary oil reserves and unconventional oil reserves, that were previously unavailable or uneconomic. We believe that current oil and natural gas prices and the existing demand for oil and natural gas will continue to result in ongoing oil and natural gas-related drilling in the United States as producers seek to increase their production levels. In particular, we believe that drilling activity targeting oil with associated natural gas, such as on our Bazor Ridge and Chatom systems, will remain active. We also believe that the current relatively low natural gas price environment will encourage the development of net industrial facilities that consume natural gas, which will benefit our transmission systems that are strategically located next to inland waterways, such as our AlaTenn and Midla complexes. Although we anticipate continued exploration and production activity in the areas in which we operate, fluctuations in energy prices can affect natural gas production levels over time as well as the timing and level of investment activity by third parties in the exploration for and development of new oil and natural gas reserves. We have no control over the level of oil and natural gas exploration and development activity in the areas of our operations.

Impact of Interest Rates

The credit markets recently have experienced near-record lows in interest rates. As the overall economy strengthens, it is likely that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. If this occurs, interest rates on floating rate credit facilities and future offerings in the debt capital markets could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price will be impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related 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 common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, reduce debt or for other purposes.

Credit markets continue to experience near-record lows, which we believe will continue through 2013; however, if monetary policy begins to tighten, our interest rates on floating rate debt facilities and future offerings in the debt capital markets could be higher. An increase in financing costs may affect yield requirements of investors who invest in our common units.

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.

Other Matters

We believe the diversity of our assets and our hedged commodity position to protect against downside commodity risk are key elements to long-term growth and sustainable distributable cash flow.

We continue to actively manage our capital maintenance and capital program. On August 13, 2012, we announced a growth project and expect to construct a midstream system to gather, treat, compress and process natural gas from wells targeting multiple liquids-rich producing formations, including the Eaglebine Formation. The anticipated midstream system would include gathering and processing capacity to support customers' production as well as other third-party development in the area. We have completed construction on the initial phase of the midstream infrastructure and began operations in early 2013.

In our Gathering and Processing segment, favorable oil prices are supporting drilling activity in the liquids-rich Upper Smackover formation, which continues to benefit our Bazor Ridge and Chatom systems. In our Transmission segment, as a result of lower natural gas prices, we have seen increased interest from the industrial and utility markets in northern Alabama and southwestern Mississippi, which we believe will positively impact our AlaTenn and Midla systems.

Our expectations are based on assumptions we made 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.

Recent Events

On April 15, 2013, the Partnership, our general partner and AIM Midstream Holdings, LLC, an affiliate of American Infrastructure MLP Fund, entered into agreements with High Point Infrastructure Partners, LLC, an affiliate of ArcLight Capital Partners, LLC (“High Point”), pursuant to which High Point (i) acquired 90% of our general partner, which holds all of our general partner units and incentive distribution rights, 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 convertible preferred units (the “Series A Preferred Units”) issued by the Partnership. As a result of these transactions, which were also consummated on April 15, 2013, High Point acquired both control of our general partner and a majority of our outstanding limited partnership interests. Please read "— ArcLight Transactions."

Contemporaneously with the consummation of these transactions, we also entered into a Fourth Amendment to our credit agreement that, among other things, provides for the waiver of recent covenant breaches relating to consolidated total leverage ratio, modifies the covenant relating to total leverage ratio through the quarter ended December 31, 2014 and reduces the quarterly cash distribution that would otherwise be payable in respect of our subordinated units or Series A Preferred Units for the first, second, third and fourth quarters of 2013. Please read "— Fourth Amendment to Credit Facility" and "—Liquidity and Capital Resources — Our Credit Facility" for more information about our credit facility, covenant violations and related waivers and the Fourth Amendment.

ArcLight Transactions

Purchase Agreement

On April 15, 2013, AIM Midstream Holdings and High Point entered into a Purchase Agreement, pursuant to which High Point purchased from AIM Midstream Holdings all of the Partnership's 4,526,066 subordinated units and 90% of the limited liability company interests in our general partner, which holds all of our general partner units and incentive distribution rights. The transactions contemplated by the Purchase Agreement were consummated on April 15, 2013. Of the cash consideration paid to AIM Midstream Holdings, $12.5 million is being held in escrow until its release upon satisfaction of certain conditions.

Contribution Agreement

On April 15, 2013, the Partnership and High Point entered into a Contribution Agreement, pursuant to which High Point contributed to us 100% of the limited liability company interests in certain of its subsidiaries that own midstream assets located in southern and offshore Louisiana (the “High Point Assets”) and $15 million in cash in exchange for 5,142,857 newly issued Series A Preferred Units. Of the $15.0 million cash consideration paid by High Point, approximately $2.5 million was used to pay certain transaction expenses of High Point, and the remaining approximately $12.5 million was used to repay borrowings outstanding under the Partnership's June 2012 amended credit facility in connection with the Fourth Amendment. The transactions contemplated by the Contribution Agreement were consummated on April 15, 2013.

Third Amended & Restated Agreement of Limited Partnership

On April 15, 2013, our general partner amended our partnership agreement with the Third Amended & Restated Agreement of Limited Partnership (the “Amended Partnership Agreement”) providing for the creation and designation of the rights, preferences, terms and conditions of the Series A Preferred Units.

Under the terms of the Amended Partnership Agreement, commencing with the quarter ending on June 30, 2013 and ending with the earlier of the quarter that includes a conversion of the Series A Preferred Units and the quarter beginning October 1, 2014 (the “Coupon Conversion Quarter”), the Series A Preferred Units will each receive quarterly distributions (the “Series A Quarterly Distributions”) in an amount equal to (i) 0.01428571 of additional Series A Preferred Units (subject to customary anti-dilution adjustments) (the "PIK Distribution") and (ii) $0.25 in cash (with the additional Series A Preferred Units and cash portion relating to the quarter ending June 30, 2013 being prorated based on the number of days in such quarter that follow the date on which the Series A Preferred Units were issued). Commencing with the Coupon Conversion Quarter, the Series A Preferred Units will receive the Series A Quarterly Distributions in an amount equal to the greater of (a) the amount of aggregate distributions that would be payable had such Series A Preferred Units converted into Common Units and (b) a fixed rate of 0.023571428 multiplied by the conversion price, which will initially be $17.50 per Series A Preferred Unit (subject to customary anti-dilution adjustments) (the “Conversion Price”), paid in arrears within 45 days after the end of each quarter and prior to distributions with respect to the Common Units and Subordinated units. If we elect to reduce distributions on the Series A Preferred Units in order to satisfy our obligation under the Fourth Amendment to reduce distributions on either our subordinated units or Series A Preferred Units in respect of each of the quarters ending June 30, September 30 and December 31, 2013, no part of any such reduction will accrue or accumulate or bear interest.

The record date for the determination of holders entitled to receive Series A Quarterly Distributions will be the same as the record date for determination of Common Unit holders entitled to receive quarterly distributions.

If we fail to pay in full any Series A Quarterly Distribution, the amount of such unpaid distribution will accrue, accumulate and bear interest at a rate of 6.0% per annum from the first day of the quarter immediately following the quarter for which such distribution is due until paid in full.

The Series A Preferred 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 Preferred Unit entitled to one vote for each Common Unit into which such Series A Preferred Unit is convertible. The Series A Preferred Units also have separate class voting rights on any matter, including a merger, consolidation or business combination, that adversely affects, amends or modifies any of the rights, preferences, privileges or terms of the Series A Preferred Units. Moreover, the general partner may not take any of the following actions without the prior written consent of High Point or any of its affiliates, as long as High Point or such affiliates together hold at least 50% of the Series A Preferred Units and Subordinated Units held by High Point immediately following the issuance of the Series A Preferred Units on April 15, 2013:

- cause or permit us to invest in, or dispose of, the equity securities or debt securities of any person or otherwise acquire or dispose of any interest in any person, to acquire or dispose of interest in any joint venture or partnership or any similar arrangement with any person, or to acquire or dispose of assets of any person, or to make any capital expenditure (other than maintenance capital expenditures), or to make any loan or advance to any person if the total consideration (including cash, equity issued and debt assumed) paid or payable, or received or receivable, by us exceeds $15 million in any one or series of related transactions or in the aggregate exceeds $50 million in any twelve-month period;

- cause or permit us to (i) incur, create or guarantee any indebtedness that exceeds (x) $75 million in any one or series of related transactions to the extent the proceeds of such financing are used to refinance our existing indebtedness, or (y) $25 million in any twelve-month period to the extent such indebtedness increases our aggregate indebtedness or (ii) incur, create or guarantee any indebtedness with a yield to maturity exceeding ten percent;
- authorize or permit the purchase, redemption or other acquisition of Partnership interests (or any options, rights, warrants or appreciation rights relating to the Partnership interests) by us;

- select or dismiss, or enter into any employment agreement or amendment of any employment agreement of, the chief executive officer and the chief financial officer of the Partnership or its subsidiary, American Midstream, LLC;
- enter into any agreement or effect any transaction between us or any of our subsidiaries, on the one hand, and any affiliate of the Partnership or the general partner, on the other hand, other than any transaction in the ordinary course of business and determined by the board of directors of the general partner to be on an arm's length basis; or
- cause or permit us or any of our subsidiaries to enter into any agreement or make any commitment to do any of the foregoing.

The Series A Preferred Units are convertible in whole or in part into Common Units at any time after January 1, 2014 or, prior to that date, with the consent of the required lenders under the June 2012 amended credit agreement, at the holder's election. The number of Common Units into which a Series A Preferred Unit is convertible will be an amount equal to (i) the sum of $17.50 and all accrued and accumulated but unpaid distributions, divided by (ii) the Conversion Price, which will initially be $17.50 per Series A Preferred Unit (subject to customary anti-dilution adjustments) (the “Conversion Rate”).

In the event that the Partnership issues, sells or grants any Common Units or convertible securities at an indicative per Common Unit price that is less than $17.50 (subject to customary anti-dilution adjustments), then the Conversion Rate will be adjusted according to a formula to provide an increase in the number of Common Units into which Series A Preferred Units are convertible.

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 Preferred Units to redeem all (but not less than all) of such holder's Series A Preferred Units for a price per Series A Preferred 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 Preferred Unit; and
- an amount equal to the product of:

(i) the number of Common Units into which each Series A Preferred 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 Preferred 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 Preferred Units without material abridgement.

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 Preferred 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 the $17.50 multiplied by the number of Series A Preferred Units owned by such holders, plus all accrued but unpaid distributions on such Series A Preferred Units.

Change of Control of the General Partner and the Partnership

Through the acquisition of the 90% interest in our general partner, the acquisition of all of our 4,526,066 subordinated units and the issuance of the 5,142,857 Series A Units, High Point acquired control of our general partner and a majority of our outstanding limited partnership interests. In connection with High Point's acquisition of control of our general partner, each of Robert B. Hellman, Jr., Edward O. Diffendal and L. Kent Moore resigned from the board of directors of our general partner. Mr. Hellman also resigned as chairman of the board of directors of our general partner. These resignations occurred on April 15, 2013. High Point, as the owner of 90% of the limited liability company interests in our general partner, will have the right to fill the board vacancies created by these resignations. Effective April 15, 2013, High Point appointed Messrs. Bergstrom, Erhard and Revers to the board of directors of our general partner. Please read "Part III, Item 10. Directors, Executive Officers and Corporate Governance" for more information about the new directors.

Fourth Amendment to Credit Agreement

On April 15, 2013, a subsidiary of the Partnership, American Midstream, LLC, as borrower (the "Borrower") and the Partnership entered into a Fourth Amendment with its lenders under its June 2012 amended credit agreement. The Fourth Amendment provides for the following:

- Permits the consummation of the ArcLight Transactions and the PIK Distribution according to the terms of the Amended Partnership Agreement;

- The aggregate commitments of the lenders under the June 2012 amended credit agreement will be reduced to $175 million if an equity contribution of $12.5 million has not been made by AIM Midstream Holdings and used to repay borrowings under the June 2012 amended credit facility by October 1, 2013;
- The total outstanding borrowings under the June 2012 amended credit facility shall not exceed $175 million until such equity contribution by AIM Midstream Holdings has occurred;
- The margins relating to our (i) Eurodollar-based loans range from 2.50% to 4.75% depending on the Consolidated Total Leverage ratio then in effect, and (ii) base rate loans range from 1.5% to 3.75%;
- The definition of Consolidated Total Indebtedness will not include the Series A Preferred Units or certain surety bonds relating to the High Point Assets;
- The definition of Consolidated EBITDA (the consolidated EBITDA for the quarters ending June 30 and September 30, 2013 will be annualized for purposes of the Consolidated Total Leverage Ratio) will:

include, on a pro forma basis, the consolidated EBITDA of the High Point Subsidiaries as if they were owned by the Partnership beginning on January 1, 2013;

exclude any insurance proceeds attributable to any event occurring prior to January 1, 2013; and

exclude any one-time, non-recurring transaction expenses of the Partnership incurred in connection with the ArcLight Transactions or the Fourth Amendment.

- Starting with the quarter ending March 31, 2013 and ending with the quarter ending December 31, 2013, unless the Partnership has permanently cancelled at least 20% of the number of subordinated units outstanding on April 15, 2013, the Partnership must reduce any quarterly cash distribution on either its subordinated units or Series A Preferred Units (at the Partnership's election) by an aggregate of $0.4 million per quarter, and such reduction may not be replaced by in-kind distributions of Partnership securities;
- The maximum Consolidated Total Leverage Ratio permitted as of the end of any fiscal quarter cannot exceed the ratio set forth below:

Fiscal Quarter Ending	Consolidated Total Leverage Ratio
June 30, 2013	5.90:1.00
September 30, 2013	5.90:1.00
December 31, 2013	5.75:1.00
March 31, 2014	5.75:1.00
June 30, 2014	5.75:1.00
September 30, 2014	5.50:1.00
December 31, 2014	5.25:1.00
March 31, 2015 and each fiscal quarter thereafter	4.50:1.00

- The Partnership agrees to cooperate with and pay the fees and expenses incurred by Bank of America, N.A., the administrative agent for the June 2012 amended credit agreement, in connection with its engagement of FTI Consulting to advise and assist it in an assessment of the Partnership's financial condition; and
- The lenders permanently waived the Partnership's failure to comply with covenants relating to the Partnership's Consolidated Total Leverage Ratio for the quarters ended December 31, 2012 and March 31, 2013.

Results of Operations — Combined Overview

Our distributable cash flow for the year ended December 31, 2012 was $9.6 million. We distributed $16.1 million to our unitholders or $1.73 per unit. For the year ended December 31, 2012, gross margin increased to $50.6 million or 10.2% compared to the same period in 2011. The increase in gross margin was largely a result of the acquisitions of a 50% undivided, non-operating, interest in the Burns Point Plant effective November 1, 2011 and of a 87.4% undivided interest in the Chatom system, effective July 1, 2012 which contributed incremental gross margin of $3.7 million and $5.8 million, respectively. This positive performance was tempered, in part, by the impact of production shut-ins due to Hurricane Isaac, an extended turnaround at our Bazor Ridge system, and reduced gathering and processing volumes associated with one of our offshore pipeline systems which in turn negatively impacted our financial performance in the third and fourth quarters of 2012.

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.

	For the Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Statement of Operations Data:			
Revenue	$209,594	$248,282	$212,248
Realized gain (loss) on early termination of commodity derivatives	—	(2,998)	—
Unrealized gain (loss) on commodity derivatives	992	(541)	(308)
Total revenue	210,586	244,743	211,940
Operating expenses:			
Purchases of natural gas, NGLs and condensate	155,667	202,403	173,821
Direct operating expenses	18,202	12,856	12,187
Selling, general and administrative expenses	14,309	10,794	7,120
Advisory services agreement termination fee	—	2,500	—
Transaction expenses	—	282	303
Equity compensation expense (a)	1,783	3,357	1,734
Depreciation expense	21,414	20,705	20,013
Total operating expenses	211,375	252,897	215,178
Gain (loss) on acquisition of assets	—	565	—
Gain (loss) on involuntary conversion of property, plant and equipment	(1,021)	—	—
Gain (loss) on sale of assets, net	128	399	—
Operating income (loss)	(1,682)	(7,190)	(3,238)
Interest (expense)	(4,570)	(4,508)	(5,406)
Net income (loss)	$(6,252)	$(11,698)	$(8,644)
Other Financial Data:			
Gross margin (b)	$50,554	$45,879	$38,119
Adjusted EBITDA (c)	$18,277	$21,041	$18,263
Distributable cash flow (d)	$9,588	$13,212	$9,549

(a) Represents cash and non-cash costs related to our Long Term Incentive Plan (" LTIP"). Of these amounts, $1.8 million, $1.6 million and $1.2 million, for the years ended December 31, 2012, 2011 and 2010, respectively, were non-cash expenses.

(b) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Note 19 to our audited consolidated financial statements included in this Annual Report beginning on page F-1 for a discussion of how we use gross margin to evaluate our operating performance, please read "— How We Evaluate Our Operations".

(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 Operations".

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

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

Revenue. Our revenue for the year ended December 31, 2012 was $209.6 million compared to $248.3 million for the year ended December 31, 2011. This decrease of $38.7 million was primarily due to the following -

- Natural gas revenues decreased $25.8 million as a result of a decline in realized natural gas prices of $1.12/Mcf along with a decrease in natural gas sales volumes of approximately 2.0 Mmcf attributable to production shut-ins caused by Hurricane Isaac;

- NGL revenues decreased $8.8 million as a result of a decline in realized NGL prices of $0.24/gal and a decrease in NGL sales volumes of 1.3 m/gal due to a turnaround taking longer than anticipated as a result of unscheduled repairs and upgrades that slowed the turnaround process but are expected to deliver long-term, improved efficiencies at our Bazor Ridge processing facility offset by an increase in volumes from the newly acquired Chatom system;

- Transmission revenues from the transportation of natural gas decreased $13.5 million as a result of declines in realized natural gas prices on our fixed margin contracts of $1.26/Mcf amounting to $13.5 million and a decrease in sales volumes of 5% period over period; and
- Condensate revenues increased $13.8 million as a result of an increase in condensate sales volumes of 5.7 m/gal due to the newly acquired Chatom system while realized condensate prices remained consistent period over period; and

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2012 were $155.7 million compared to $202.4 million in the year ended December 31, 2011. This decrease of $46.7 million was primarily due to lower natural gas and NGL sales volumes and related realized prices related to POP contracts associated with owned processing plants in our Gathering and Processing and Transmission segments. This decrease was partially offset by higher condensate purchase costs in our Gathering and Processing segment.

Gross Margin. Gross margin for the year ended December 31, 2012 was $50.6 million compared to $45.9 million for the year ended December 31, 2011. This increase of $4.7 million was primarily due to higher throughput volume and associated condensate production from owned processing plants in our Gathering and Processing segment. This was a result of our recent acquisitions of the Burns Point Plant, effective November 1, 2011 and of the Chatom system, effective July 1, 2012 which contributed incremental gross margin of $3.7 million and $5.7 million, respectively. These increases were offset by a decline in gross margin from our Bazor Ridge and Quivira systems due to unscheduled repairs and upgrades that slowed the turnaround process amounting to $0.7 million and declined in volumes during the third and fourth quarters of 2012 as a result of a producer's work on one of its platforms amounting to approximately $2.0 million, respectively.

Direct Operating Expenses. Direct operating expenses in the year ended December 31, 2012 were $18.2 million compared to $12.9 million in the year ended December 31, 2011. This increase of $5.3 million was primarily due to: (i) $0.7 million incremental costs related to additional insurance premiums; (ii) $1.8 million of added expenses associated with our 50% undivided interest in the operating costs incurred at the Burns Point Plant; and (iii) $2.9 million of added expenses associated with our new acquired Chatom system.

Selling, General and Administrative Expenses ("SG&A"). SG&A expenses for the year ended December 31, 2012 were $14.3 million compared to $10.8 million for the year ended December 31, 2011. This increase of $3.5 million was primarily due to: (i) $1.5 million of incremental personnel costs, recruiting fees and related benefits necessary to operate and grow a public company; (ii) $0.7 million in additional legal expenses associated with SEC and other regulatory compliance; (iii) $0.8 million of incremental accounting, auditing and tax costs associated with our acquisition of the Chatom Assets and shelf registration statement; and (iv) $0.4 million of incremental costs associated with outside services and contract labor to assist in maintaining and maximizing operational efficiency of our systems and internal controls over financial reporting.

Advisory Services Agreement Termination Fee. In connection with our initial public offering in August 2011, we terminated the advisory services agreement with our sponsor in exchange for a payment of $2.5 million.

Equity Compensation Expense. Compensation expense related our LTIP for the year ended December 31, 2012 was $1.8 million compared to $3.4 million for the year ended December 31, 2011. This decrease of $1.6 million was primarily due to a 2011 buy-out of distribution equivalent rights ("DER's") associated with unvested phantom units at a cost of $1.5 million, a payment to holders of unvested phantom units without DER's of $0.1 million, increased amortization of $0.1 million associated with March 2011 phantom unit grants, off-set in part by the lack of DER payments in the second half of 2011 and a modification in amounts amortized due to the elimination of the DER's that did not occur in the year ended December 31, 2012.

Depreciation Expense. Depreciation expense in the year ended December 31, 2012 was $21.4 million compared to $20.7 million for the year ended December 31, 2011. This increase of $0.7 million was due to depreciation associated with newly acquired facilities and capital projects placed into service during the period.

Year ended December 31, 2011 compared to year ended December 31, 2010

Revenue. Our revenue for the year ended December 31, 2011 was $248.3 million compared to $212.2 million for the year ended December 31, 2010. This increase of $36.1 million was primarily due to the following -

- Natural gas revenues increased $10.0 million as a result of an increase in natural gas sales volumes of approximately 6.8 Mmcf attributable to increased production on our Gathering and Processing systems and increased throughput on our Transmission assets offset by declines in realized natural gas prices of $0.51/Mcf;
- NGL revenues increased $16.1 million as a result of an increase in realized NGL prices of $0.25/gal and an increase in NGL sales volumes of 7.2 m/gal due improved efficiencies at our Bazor Ridge processing facility;

- Condensate revenues increased $2.6 million as a result of an increase in realized condensate prices of $0.60/gal and increases in condensate sales volumes of 0.5 m/gal attributable to increased production with a producer on a Gathering and Processing system; and
- Transmission revenues from the transportation of natural gas increased approximately $13.3 million as a result of an increase in sales volumes of 52% amounting to $14.0 million period over period offset realized natural gas prices on our fixed margin contracts declining slightly by $0.05/Mcf .

Realized gain (loss) on early termination of commodity derivatives. We recognized a one-time charge of $3.0 million resulting from the unwind and reset of our commodity derivative contracts in June 2011.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2011 were $202.4 million compared to $173.8 million in the year ended December 31, 2010. This increase of $28.6 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants' POP contracts and higher natural gas purchase volumes in our Gathering and Processing and Transmission segments. This increase was partially offset by lower natural gas purchase costs in our Gathering and Processing segment.

Gross Margin. Gross margin for the year ended December 31, 2011 was $45.9 million compared to $38.1 million for the year ended December 31, 2010. This increase of $8.1 million was primarily due to higher throughput volume and associated NGL production from owned processing plants, improved processing and POP margins from higher NGL and condensate prices and higher throughput in our Gathering and Processing segment. We also achieved incremental gross margin of $1.1 million associated with our acquisition of a 50% undivided, non-operating, interest in the Burns Point Plant effective November 1, 2011. In addition this increase was also attributable to a $0.5 million increase in COMA income.

Direct Operating Expenses. Direct operating expenses in the year ended December 31, 2011 were $12.8 million compared to $12.2 million in the year ended December 31, 2010. This increase of $0.6 million was primarily due to: (i) $0.2 million incremental costs related to service fees and costs to address operational matters; (ii) $0.3 million of added expenses associated with our 50% interest in the operating costs incurred at the Burns Point Plant; and (iii) $0.4 million of line losses in our Transmission segment. The operational cost increases were partially offset by a reduction in personnel related costs.

Selling, General and Administrative Expenses. SG&A expenses for the year ended December 31, 2011 were $10.8 million compared to $7.1 million for the year ended December 31, 2011. This increase of $3.7 million was primarily due to: (i) $1.9 million of incremental personnel costs and related benefits necessary to operate and grow a public company; (ii) $0.2 million in additional expenses associated with maintaining operational locations and services; (iii) $1.0 million of added costs associated with our IPO process and continued compliance and requirements for a publicly traded company; and (iv) $0.3 million of incremental costs associated with outside services and contract labor to assist in maintaining and maximizing operational efficiency of our systems.

Advisory Services Agreement Termination Fee. In connection with our initial public offering in August 2011, we terminated the advisory services agreement with our sponsor in exchange for a payment of $2.5 million.

Equity Compensation Expense. Compensation expense related our LTIP for the year ended December 31, 2011 was $3.4 million compared to $1.7 million for the year ended December 31, 2010. This increase of $1.7 million was primarily due to a buy-out of DER's associated with unvested phantom units at a cost of $1.5 million, a payment to holders of unvested phantom units without DER's of $0.1 million, increased amortization of $0.1 million associated with March 2011 phantom unit grants, off-set in part by the lack of DER payments in the second half of 2011 and a modification in amounts amortized due to the elimination of the DER's.

Depreciation Expense. Depreciation expense in the year ended December 31, 2011 was $20.7 million compared to $20.0 million for the year ended December 31, 2010. This increase of $0.7 million was due to depreciation associated with capital projects placed into service during the period.

Results of Operations — Segment Results

The table below contains key segment performance indicators related to our segment results of operations.

	For the Year Ended December 31,		
	2012	2011	2010
	(in thousands except operational data)		
Segment Financial and Operating Data:			
Gathering and Processing segment			
Financial data:			
Revenue	$157,065	$181,517	$158,763
Realized gain (loss) on early termination of commodity derivatives	—	(2,998)	—
Unrealized gain (loss) on commodity derivatives	992	(541)	(308)
Total revenue	158,057	177,978	158,455
Purchases of natural gas, NGLs and condensate	$119,152	$149,375	$133,860
Direct operating expenses	$13,171	$7,636	$7,721
Other financial data:			
Segment gross margin	$37,241	$32,142	$24,595
Operating data:			
Average throughput (MMcf/d)	299.3	250.9	175.6
Average plant inlet volume (MMcf/d) (a)	116.1	36.7	9.9
Average gross NGL production (Mgal/d) (a)	49.9	54.5	34.1
Average gross condensate production (Mgal/d) (a)	22.6	6.8	5.1
Average realized prices:			
Natural gas ($/MMcf)	$2.98	$4.09	$4.61
NGLs ($/gal)	$1.09	$1.32	$1.08
Condensate ($/gal)	$2.30	$2.41	$1.82
Transmission segment			
Financial data:			
Total revenue	$52,529	$66,765	$53,485
Purchases of natural gas, NGLs and condensate	$36,516	$53,029	$39,961
Direct operating expenses	$5,031	$5,220	$4,466
Other financial data:			
Segment gross margin	$13,313	$13,737	$13,524
Operating data:			
Average throughput (MMcf/d)	398.5	381.1	350.2
Average firm transportation - capacity reservation (MMcf/d)	703.6	702.2	677.6
Average interruptible transportation - throughput (MMcf/d)	86.6	69.0	80.9

(a) Excludes volumes and gross production under our elective processing arrangements.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Gathering and Processing Segment

Revenue. Segment revenue for the year ended December 31, 2012 was $157.1 million compared to $181.5 million for the year ended December 31, 2011. This decrease of $24.4 million was primarily due to the following -

- A decline in realized natural gas prices of 27%, realized NGL prices of 18% and realized condensate prices of 5% period over period as a result of variable commodity prices;

- A decline in average gross NGL production amounting to 4.6 Mgal/d period over period as a result of extended turnaround efforts at the our Bazor Ridge system during the fourth quarter, offset by;
- An increase in average throughput amounting to 40.4 MMcf/d or 16% period over period as a result of having a full year's operational impact of our 50% undivided interest in the Burns Point plant offset by declines in average throughput associated with our Quivera and Gloria systems as well as production shut-ins surrounding our Gulf Coast systems during the third quarter as result of Hurricane Isaac;
- A significant increase in average gross condensate production amounting to 15.7 Mgal/d period over period as a result of our our newly acquired Chatom system in the third quarter of 2012; and
- An increase in realized gains of $4.3 million period over period on our commodity derivatives which comprised of financial swaps and option contracts to mitigate commodity price risk that settled in 2012.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2012 were $119.2 million compared to $149.4 million for the year ended December 31, 2011. This decrease of $30.2 million was primarily due to lower natural gas and NGL sales volumes and related realized commodity prices related to POP contracts associated with our Bazor Ridge system. This decrease was partially offset by higher condensate sales volumes associated with the newly acquired Chatom system, effective July 1, 2012 and higher NGL sales volumes at the Burns Point Plant.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2012 was $37.2 million compared to $32.1 million for the year ended December 31, 2011. This increase of $5.1 million was primarily due to the following -

- Incremental gross margin of $5.6 million associated with higher average condensate production of 17.1 Mgal/d as a result of the new acquired Chatom system, effective July 1, 2012;
- Incremental gross margin of $2.5 million associated with higher average throughput of 76.4 Mcf/d and NGL production of 7.7 Mgal/d as a result of having a full year of operational results of the Burns Point plant, acquired effective November 1, 2011, offset by lower gross margins of $1.3 million associated with our Quivira system which saw a decline in volumes on one of its offshore pipeline systems during the third and fourth quarters of 2012 as a result of a producer completing work on one of its platforms. The Partnership continued to work with this producer to return volumes to historical levels, although the contract terms may change for a portion of the volumes going forward and a change in contract terms may have a material negative impact on financial results;
- A decline in gross margin of $1.8 million associated with lower NGL production of 14.9 Mgal/d at our Bazor Ridge processing plant due to a turnaround taking longer than anticipated as a result of unscheduled repairs and upgrades that slowed the turnaround process but are expected to deliver long-term, improved efficiencies at our Bazor Ridge processing facility;
- Gross margins associated with facilities damaged and/or impacted by production shut-ins as a result of the named windstorm Hurricane Isaac were estimated to approximate $0.8 million are covered by our insurance carrier; and
- An increase in realized gains of $4.3 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 2012.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2012 were $13.2 million compared to $7.6 million for the year ended December 31, 2011. This increase of $5.6 million was primarily due (i) $0.6 million incremental costs related to additional insurance premiums; (ii) $1.7 million of added expenses associated with operating costs incurred at the Burns Point Plant; and (iii) $2.5 million of added expenses associated with operating costs incurred at our Chatom system.

Transmission Segment

Revenue. Segment revenue for the year ended December 31, 2012 was $52.5 million compared to $66.8 million for the year ended December 31, 2011. This decrease of $14.3 million in revenue was primarily due to the following -

- A decline in realized natural gas prices on our fixed margin contracts of $1.26/Mcf along with a decline in sales volumes of 5% amounting to $13.5 million period over period;
- Total natural gas throughput on our Transmission systems for the year ended December 31, 2012 was 398.5 MMcf/d compared to 381.1 MMcf/d for the year ended December 31, 2011 representing a 5% increase period over period; and
-

Lower transportation fees associated with our interruptible transportation contracts offset by an increase in throughput of 17.5 MMcf/d amounting to amounting to $0.5 million period over period.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2012 were $36.5 million compared to $53.0 million for the year ended December 31, 2011. This decrease of $16.5 million was primarily due to a decrease in our purchases costs associated with fixed margin contracts as a result of a decline in natural gas market prices and sales volumes.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2012 was $13.3 million compared to $13.7 million for the year ended December 31, 2011. This decrease of $0.4 million was primarily associated with a slight change to our contract mix of fixed margin, firm and interruptible transportation contracts offset by a slight increase in throughput volumes period over period.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2012 were $5.0 million compared to $5.2 million for the year ended December 31, 2011. This decrease of $0.2 million was primarily due to lower property taxes incurred period over period.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Gathering and Processing Segment

Revenue. Segment revenue for the year ended December 31, 2011 was $181.5 million compared to $158.8 million for the year ended December 31, 2010. This increase of $22.7 million was primarily due to the following -

- Increases in realized NGL prices of 22% and realized condensate prices of 33%, offset by a decline in realized natural gas prices of 11% period over period as a result of variable commodity prices;
- An increase in average gross NGL production amounting to 20.4 Mgal/d or 60% period over period as a result of the completion of our Winchester lateral in the fourth quarter of 2010 and the production from several new wells drilled in 2011 on our Bazor Ridge system;
- An increase in average throughput amounting to 75.3 MMcf/d or 43% period over period as a result of higher natural gas sales volumes, i) primarily the increased demand at the Conoco Alliance refinery, which we serve with production from our Lafitte system and our interconnect with the Tennessee Gas Pipeline representing an increase of 28% year over year; ii) additional natural gas production from a producer on our Quivira system in the third quarter 2010 representing a 43% increase year over year; and iii) new incremental throughput volume from the Burns Point Plant from the 50% interest we acquired effective November 1, 2011; offset by
- A series of swap and put contracts that we entered into in January 2011 and swap contracts again in June 2011. These commodity derivative transactions had a negative net effect of $1.9 million on our revenue related to realized losses for the year ended December 31, 2011. In June 2010, we purchased put contracts that extended through June 2011.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2011 were $149.4 million compared to $133.9 million for the year ended December 31, 2010. This increase of $15.5 million was primarily due to higher NGL sales volumes and NGL prices related to owned processing plants' POP contracts and higher natural gas purchase volumes to provide natural gas for the Conoco Alliance refinery. This increase was partially offset by lower natural gas prices.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2011 was $32.1 million compared to $24.6 million for the year ended December 31, 2010. This increase of $7.9 million was primarily due to the following -

- Higher throughput volume and associated NGL production of 16.0 Mgal/d or 16% at our Bazor Ridge processing plant;
- Increased throughput volume of 33.4 MMcf/d or 43% on our Quivira system;
- Higher realized NGL prices of $1.32/gal which positively impacted margins associated with our POP and elective processing agreements; and
- The acquisition of our 50% interest in the Burns Point Plant, effective November 2011; offset by
- Commodity derivative transactions that had a negative net effect of $1.9 million on our margin related to realized losses for the year ended December 31, 201

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2011 were $7.6 million compared to $7.7 million for the year ended December 31, 2010.

Transmission Segment

Revenue. Segment revenue for the year ended December 31, 2011 was $66.8 million compared to $53.5 million for the year ended December 31, 2010. Total natural gas throughput on our Transmission systems for the year ended December 31, 2011 was 381.1MMcf/d compared to 350.2 MMcf/d in the year ended December 31, 2010. This increase of $13.3 million in revenue was primarily due to a full year's impact of our fixed margin agreement which began in the second quarter 2010 to supply gas to Exxon on our MLGT system offset in part by lower volumes and natural gas prices associated with an affiliate fixed margin agreement on the Midla system. Our commodity derivatives had no effect on segment revenue for the years ended December 31, 2011 and 2010.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2011 were $53.0 million compared to $40.0 million for the year ended December 31, 2010. This increase of $13.0 million was primarily due to a full year's impact of our fixed margin agreement began in the second quarter 2010 to supply gas to Exxon on our MLGT system offset in part by lower volumes and natural gas prices associated with an affiliate fixed margin agreement on the Midla system.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2011 was $13.7 million compared to $13.5 million for the year ended December 31, 2010. Segment gross margin for the Transmission segment represented 29.7% of our total gross margin for year ended December 31, 2011, compared to 35.5% for the year ended December 31, 2010.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2011 were $5.2 million compared to $4.5 million for the year ended December 31, 2010. This increase of $0.7 million was primarily due to $0.2 million incremental costs related to service fees and costs to address operational matters and a $0.5 million increase in line losses.

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 indicators of our liquidity at December 31, 2012 were our cash on hand and availability under our June 2012 amended credit facility as it existed prior to the Fourth Amendment as discussed below. As of December 31, 2012, our available liquidity was $19.7 million, comprised of cash on hand of $0.6 million and $19.1 million available under our June 2012 amended credit facility as it existed at that time. As of March 31, 2013, our available liquidity was $9.1 million. In the near term, we expect our sources of liquidity to include cash generated from operations, borrowings under our June 2012 amended credit facility and issuances of debt and equity securities. As a result of the contribution of the High Point assets to the Partnership (with the resultant expected increase in the Partnership's EBITDA for the trailing twelve months), Fourth Amendment, the PIK Distribution on the Series A Preferred Units and the Preferred Unit Distribution Waiver, we expect to generate sufficient cash flow from operations and borrowings under our June 2012 amended credit facility, as needed, to:

- pay the required distribution on the Series A Convertible Preferred Units (a portion of which is payable in-kind in additional Series A Preferred Units ("Series A PIK Units"), less the Preferred Unit Distribution Waiver;
- pay at least the minimum quarterly distribution on all outstanding common units, subordinated units, and general partner units; and
- meet our requirements for working capital and capital expenditures,

in each case, for the next twelve months from the date of this Annual Report on Form 10-K. Please read "— Our Credit Facility" for more information about our June 2012 amended credit facility. Please see "Recent Developments — ArcLight Transactions" for more information about the ArcLight Transactions.

We depend on our June 2012 amended credit facility for future capital needs and may use it to fund a portion of cash distributions to unitholders, as necessary, depending on the level of our operating cashflow. 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 June 2012 amended credit facility could result in a default, which could cause all of our existing indebtedness to become immediately due and payable. We were unable to maintain compliance with consolidated total leverage ratio required by our June 2012 amended credit agreement as it existed prior to the Fourth Amendment during the quarters ended December 31, 2012 and March 31, 2013. On April 15, 2013, we entered into a Fourth Amendment to our June 2012 amended credit agreement that, among other things, modified the maximum permitted consolidated total leverage ratio. The maximum consolidated total leverage ratio permitted by the Fourth Amendment varies by quarter, initially permitting a ratio of 5.90 to 1.00 for the quarter ending June 30, 2013 and then gradually lowering to 4.50 to 1.00 commencing with the quarter ending March 31, 2015. The Partnership believes that the consummation of the ArcLight Transactions will allow it to maintain compliance with the Consolidated Total Leverage to EBTIDA ratio in the Fourth Amendment for a period of at least the next twelve months from the date of the Annual Report on

Form 10-K. However, no assurances can be given that the ArcLight Transactions will achieve the necessary ratios or that the contributed business can yield the necessary cash flows. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Our Credit Facility" for more information about the Fourth Amendment and our June 2012 amended credit facility.

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 $3.6 million at December 31, 2012.

Cash Flows

The following table reflects cash flows for the applicable periods:

(in thousands)	For the Year Ended December 31,		
	2012	2011	2010
Net cash provided by (used in):			
Operating activities			