SOUTHCROSS ENERGY

THE SOUTHCROSS ADVANTAGE

ABOUT SOUTHCROSS ENERGY PARTNERS, L.P.

Southcross Energy Partners, L.P. ("Southcross") is a master limited partnership that provides natural gas gathering, processing, treating, compression and transportation services, and NGL fractionation and transportation services. It also sources, purchases, transports and sells natural gas and NGLs. Its assets are located in South Texas, Mississippi and Alabama, and include four gas processing plants, two fractionation plants and approximately 3,000 miles of pipeline. The South Texas assets are located in or near the Eagle Ford Shale region.

SOUTHCROSS IS HEADQUARTERED IN DALLAS, TEXAS, AND TRADES ON THE NYSE UNDER THE TICKER "SXE"

THE SOUTHCROSS ADVANTAGE

PREMIER STRATEGIC PLATFORM IN THE EAGLE FORD

- Significant scale of pipeline and processing assets
- Operating stability through interconnected system
- Extensive footprint in the prolific Eagle Ford and Gulf Coast area
- Premier active producer customer base

FULLY INTEGRATED MIDSTREAM PLATFORM

- Full spectrum of services creating competitive and economic advantages
- Fractionation assets are a significant differentiator
- Connection to premium and growing markets for gas, NGLs and condensate
- Access to growing Corpus Christi-area petrochemical, industrial and export markets

MULTIPLE DRIVERS OF GROWTH

- Increased utilization of existing capacity
- Development of organic growth projects
- Execution of drop-downs from our holding company

SOUTHCROSS ENERGY



Dear Fellow Unitholders,

2014 WAS A LANDMARK YEAR FOR SOUTHCROSS ENERGY.

During the course of 2014, we completed a significant acquisition of gathering and processing assets in the Eagle Ford Shale region, successfully executed several organic projects that resulted in meaningful growth of rich gas volumes on our system, and added significant potential drop-down assets together with new equity capital at our holding company. Along the way, we significantly strengthened our financial position, delivered progressively positive operational and financial results, and added new private equity sponsor partners to the ownership of our holding company.

Our August 2014 combination with TexStar Midstream Services, LP and the resulting creation of Southcross Holdings provided our unitholders with a wealth of opportunities for future growth and performance. With our four processing plants, two fractionation facilities, over 3,000 miles of pipeline, and access to additional infrastructure at our holding company, Southcross has a portfolio of assets that ensures both the benefits of expanded scale and increased operational stability. Our fully integrated midstream platform and our strategic focus on the growing Corpus Christi petrochemical market provide us with competitive and economic advantages to fill our current and future capacity. We believe that these core strengths, combined with our growth prospects, represent the Southcross Advantage.

2014 also marked a change in our leadership, as David Biegler transitioned into his focused role as Chairman of the Board, having led Southcross for the last five years as Chairman and Chief Executive Officer. I appreciate and thank David for his leadership, and look forward to continuing to work together with him.

We look toward a future bolstered by the Southcross Advantage that will drive us forward. We have a premier strategic footprint that stretches through the core of the Eagle Ford to the growing industrial complex and export facilities at the port of Corpus Christi. We have a fully integrated midstream platform, offering our customers a full spectrum of services. We have the largest intrastate pipeline systems in both Mississippi and Alabama, and they are strategically positioned with a focus on end-use markets. We see a clear path to growth as we fill our existing capacity, develop organic growth projects and take full advantage of our new drop-down structure.

It is an exciting time to be invested in Southcross. While the current commodity price environment has created some uncertainty with regard to the broad outlook for the pace of exploration and development activity, we are confident that Southcross is well positioned. Our focus on the Eagle Ford, with its advantaged economics for our upstream producer customers, provides a path for our continued growth. With our outstanding platform and asset base and our deeply experienced and talented team of employees, we believe we are in a great place at a great time to grow our partnership in 2015 and over the longer term. It is a privilege and a pleasure to serve Southcross and its unitholders.

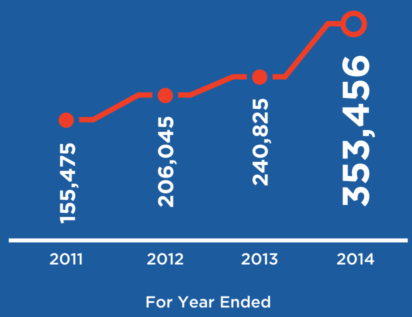
Respectfully,

JOHN E. BONN

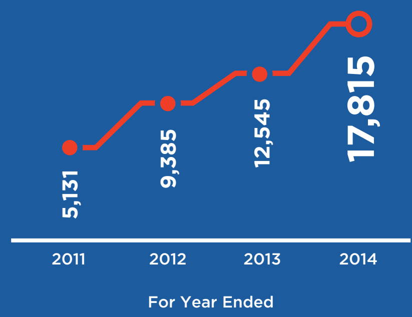
PRESIDENT AND
CHIEF EXECUTIVE OFFICER

KEY OPERATIONAL METRICS

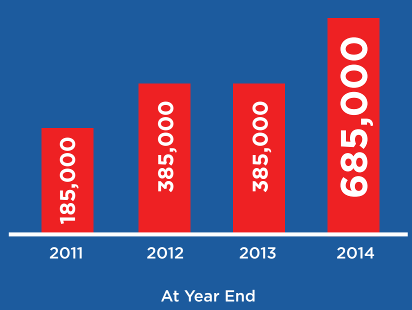
AVERAGE PROCESSED GAS VOLUMES (MMBtu/d)



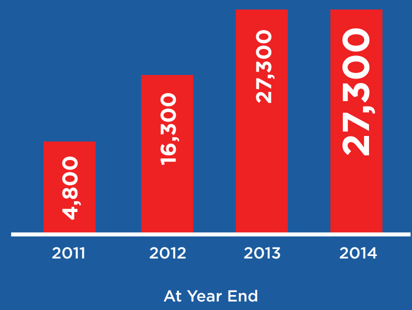
AVERAGE VOLUME OF NGLs FRACTIONATED (BBls/d)



PROCESSING CAPACITY (Mcf/d)



FRACTIONATION CAPACITY (BBls/d)



BOARD OF DIRECTORS AND EXECUTIVE OFFICERS

EXECUTIVE OFFICERS

JOHN E. BONN
PRESIDENT AND
CHIEF EXECUTIVE OFFICER

PHILLIP M. MEZEY
EXECUTIVE VICE PRESIDENT,
BUSINESS DEVELOPMENT

J. MICHAEL ANDERSON
SENIOR VICE PRESIDENT
AND CHIEF FINANCIAL OFFICER

DONNA A. HENDERSON
VICE PRESIDENT AND
CHIEF ACCOUNTING OFFICER

W. COREY LOTHAMER
VICE PRESIDENT,
GAS MARKETING AND SUPPLY

GERARDO E. RIVERA
VICE PRESIDENT,
NATURAL GAS LIQUIDS

BOARD OF DIRECTORS

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CHAIRMAN

JON M. BIOTTI
DIRECTOR

JASON H. DOWNIE
DIRECTOR

WALLACE C. HENDERSON
DIRECTOR

JERRY W. PINKERTON
DIRECTOR

RONALD G. STEINHART
DIRECTOR

BRUCE A. WILLIAMSON
DIRECTOR

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2014

OR

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

For the transition period from to

Commission file number: 001-35719

Southcross Energy Partners, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**45-5045230**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Pacific Avenue, Suite 2900 **Dallas, TX**	**75201**
(Address of principal executive offices)	(Zip Code)

(214) 979-3700
www.southcrossenergy.com
(Registrant's telephone number, including area code)

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

Title of each class	**Name of each exchange on which registered**
Common Units of Limited Partner 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 ☐ No ☒

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

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

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

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

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

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2014 was approximately $450,239,559 based on the closing sale price and the number of outstanding common units on such date as reported on the New York Stock Exchange.

As of March 2, 2015, the registrant has 23,800,943 common units, 12,213,713 subordinated units and 15,149,636 Class B Convertible Units outstanding. The registrant's common units trade on the New York Stock Exchange under the symbol "SXE".

DOCUMENTS INCORPORATED BY REFERENCE

None

Explanatory Note

As generally used in the energy industry and in this Form 10-K, the following terms have the following meanings:

/d: Per day

/gal: Per gallon

Bbls: Barrels

Condensate: Hydrocarbons that are produced from natural gas reservoirs but remain liquid at normal temperature and pressure

Lean gas: Natural gas that is low in NGL content

MMBtu: One million British thermal units

Mcf: One thousand cubic feet

MMcf: One million cubic feet

NGLs: Natural gas liquids, which consist primarily of ethane, propane, isobutane, normal butane, natural gasoline and stabilized condensate

Residue gas: The pipeline quality natural gas remaining after natural gas is processed and NGLs and other matters are removed

Rich gas: Natural gas that is high in NGL content

Throughput: The volume of natural gas or NGLs transported or passing through a pipeline, plant, terminal or other facility

y-grade: Commingled mix of NGL components extracted via natural gas processing normally consisting of ethane, propane, isobutane, butane and natural gasoline

INDEX TO ANNUAL REPORT ON FORM 10-K

For the Year Ended December 31, 2014

FORWARD-LOOKING INFORMATION

Investors are cautioned that certain statements contained in this Form 10-K as well as in periodic press releases and oral statements made by our management team during our presentations are “forward-looking” statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will be,” “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “would” and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us or our subsidiaries, are also forward-looking statements. These forward-looking statements involve external risks and uncertainties, including, but not limited to, those described under the section entitled “Risk Factors” included herein.

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond the control of our management team. All forward-looking statements in this Form 10-K and subsequent written and oral forward-looking statements attributable to us, or to persons acting on our behalf, are expressly qualified in their entirety by these risks and uncertainties. These risks and uncertainties include, among others:

- the volatility of natural gas, crude oil, and NGL prices and the price and demand of products derived from these commodities, particularly in the depressed energy price environment that began in the second half of 2014, which has the potential for further deterioration and may result in a material reduction in exploration, development and production;
- competitive conditions in our industry and the extent and success of producers increasing production or replacing declining production and our success in obtaining new sources of supply;
- industry conditions and supply of pipelines, processing and fractionation capacity relative to available natural gas from producers;
- our dependence upon a relatively limited number of customers for a significant portion of our revenues;
- actions taken or inactions or non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- our ability to effectively recover NGLs at a rate equal to or greater than our contracted rates with customers;
- our ability to produce and market NGLs at the anticipated differential to NGL index pricing;
- our access to markets enabling us to match pricing indices for purchases and sales of natural gas and NGLs;
- our ability to complete projects within budget and on schedule, including, but not limited to, timely receipt of necessary government approvals and permits, our ability to control the costs of construction and other factors that may impact projects;
- our ability to consummate acquisitions, successfully integrate the acquired businesses and realize anticipated cost savings and other synergies from any acquisitions, including with respect to our acquisition of certain gathering and processing assets from TexStar Midstream Services, LP in August 2014;
- our ability to manage over time changing exposure to commodity price risk;
- the effectiveness of our hedging activities or our decisions not to undertake hedging activities;
- our access to financing and ability to remain in compliance with our financing covenants, and the potential for lack of access to debt capital markets if the depressed energy price environment that began in the second half of 2014 continues;

- our ability to generate sufficient operating cash flow to fund our quarterly distributions;
- changes in general economic conditions;
- the effects of downtime associated with our assets or the assets of third parties interconnected with our systems;
- operating hazards, fires, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the failure of our processing and fractionation plants to perform as expected, including outages for unscheduled maintenance or repair;
- the effects of laws and governmental regulations and policies;
- the effects of existing and future litigation; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our filings with the U.S. Securities and Exchange Commission.

Developments in any of these areas could cause actual results to differ materially from those anticipated or projected, affect our ability to maintain distribution levels and/or access necessary financial markets or cause a significant reduction in the market price of our common units.

The foregoing list of risks and uncertainties may not contain all of the risks and uncertainties that could affect us. In addition, in light of these risks and uncertainties, the matters referred to in the forward-looking statements contained in this report may not, in fact, occur. Accordingly, undue reliance should not be placed on these statements. We undertake no obligation to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law.

PART I

Item 1. Business

The following discussion of our business provides information regarding our principal gathering, transportation, processing, NGL fractionation and other assets. For a discussion of our results of operations, please read Part II, Item 7 of this report.

General Overview

Southcross Energy Partners, L.P. (the "Partnership," "Southcross," "we," "our" or "us") is a Delaware limited partnership formed in April 2012. Southcross Energy LLC is a Delaware limited liability company, and the predecessor for accounting purposes (the "Predecessor") of the Partnership. References in this Form 10-K to the Partnership, when used for periods prior to our initial public offering ("IPO") on November 7, 2012, refer to Southcross Energy LLC and its consolidated subsidiaries, unless otherwise specifically noted. References in this Form 10-K to the Partnership, when used for periods beginning at or following our IPO, refer collectively to the Partnership and its consolidated subsidiaries. Until August 4, 2014, Southcross Energy LLC held all of the equity interests in Southcross Energy Partners GP, LLC, a Delaware limited liability company and our general partner ("General Partner"), all of our subordinated units, as well as a portion of our common units and Series A Convertible Preferred Units ("Series A Preferred Units"). Southcross Energy LLC is controlled through investment funds and entities associated with Charlesbank Capital Partners, LLC ("Charlesbank").

On August 4, 2014, Southcross Energy LLC and TexStar Midstream Services, LP ("TexStar") combined pursuant to a contribution agreement in which Southcross Holdings LP, a Delaware limited partnership ("Holdings"), was formed (the "Holdings Transaction"). As a result of the Holdings Transaction, Holdings owns 100% of our General Partner (and therefore controls us), all of our subordinated units and a portion of our common units. Charlesbank, EIG Global Energy Partners, LLC ("EIG") and Tailwater Capital LLC ("Tailwater") (collectively, the "Sponsors") each indirectly own approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine Opportunities Fund and GE Energy Financial Services own certain additional ownership interests in Holdings as well.

We are a master limited partnership that provides natural gas gathering, processing, treating, compression and transportation services and NGL fractionation and transportation services. We also source, purchase, transport and sell natural gas and NGLs. Our assets are located in South Texas, Mississippi and Alabama and include four gas processing plants, two fractionation facilities and approximately 3,005 miles of pipeline. We are headquartered in Dallas, Texas.

Recent Developments

Public Offering

In February 2014, we completed a public equity offering of 9,200,000 additional common units and we received a capital contribution from our General Partner to maintain its 2.0% interest in us. The net proceeds from the public offering were $144.7 million. The net proceeds from the offering were used for our Onyx acquisition in March 2014, to fund the construction of our new pipeline extending into Webb County, Texas and for general partnership purposes.

Onyx Pipelines Acquisition

On March 6, 2014, our subsidiary, Southcross Nueces Pipelines LLC, acquired natural gas pipelines near Corpus Christi, Texas and contracts related to these pipelines from Onyx Midstream, LP and Onyx Pipeline Company (collectively, "Onyx") for $38.6 million in cash, net of certain adjustments as provided in the purchase agreement. See Note 3 to our consolidated financial statements.

TexStar Rich Gas System Transaction

Contemporaneously with the closing of the Holdings Transaction, TexStar contributed to us certain gathering and processing assets (the "TexStar Rich Gas System"), owned by it (the "TexStar Rich Gas System Transaction"). For additional details regarding the Holdings Transaction and the TexStar Rich Gas System Transaction, see Notes 1, 3, 8, 10, 14 and 17 to our consolidated financial statements.

Senior Credit Facilities

On August 4, 2014, in connection with the consummation of the Holdings Transaction, we entered into (a) a Third Amended and Restated Revolving Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, JPMorgan Chase Bank, N.A., as Documentation Agent, and a syndicate of lenders (the "Third A&R Revolving Credit Agreement") and (b) a Term Loan Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, and a syndicate of lenders (the "Term Loan Agreement" and, together with the Third A&R Revolving Credit Agreement, the "Senior Credit Facilities").

Equity Distribution Agreement

On November 12, 2014, we established a $75 million "at-the-market" equity offering program pursuant to an equity distribution agreement (the "Distribution Agreement") with Wells Fargo Securities, LLC, J.P. Morgan Securities LLC and RBC Capital Markets, LLC (each, a "Manager" and, collectively, the "Managers"). Under the Distribution Agreement, we may offer and sell up to $75 million in aggregate gross sales proceeds of our common units (the "Offered Units") from time to time through the Managers, each as our sales agent. Sales of the Offered Units, if any, made under the Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices prevailing at the time of sale in block transactions, or as otherwise agreed upon by us and any Manager. For additional details regarding the Distribution Agreement, see Note 12 to our consolidated financial statements.

Subordinated Unit Distribution Waiver

Beginning with the third quarter of 2014, until such time that we have a ratio of distributable cash flow divided by cash distributions ("Distributable Cash Flow Ratio") of at least 1.0, Holdings, the holder of all of our subordinated units, has waived the right to receive distributions on any subordinated units that would cause the Distributable Cash Flow Ratio to be less than 1.0. With respect to the fourth quarter of 2014, Holdings waived the requirement that any distribution owed to it for that quarter be paid within 45 days of the end of the quarter, provided that the distribution is paid before or in conjunction with the filing of this Form 10-K.

Emerging Growth Company Status

We are an "emerging growth company," as defined in the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). For as long as we are deemed an emerging growth company, we may take advantage of specified reduced reporting and other regulatory requirements that are generally unavailable to other public companies. These provisions include:

- an exemption from the auditor attestation requirement in the assessment of the emerging growth company's internal controls over financial reporting;
- an exemption from the adoption of new or revised financial accounting standards until they would apply to private companies;
- an exemption from compliance with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; and

- reduced disclosure about the emerging growth company's executive compensation arrangements pursuant to the rules applicable to smaller reporting companies.

We may take advantage of these provisions until we are no longer an emerging growth company, which will occur on the earliest of:

i. the last day of the fiscal year following the fifth anniversary of our IPO;

ii. the last day of the fiscal year in which we have more than $1.0 billion in annual revenues;

iii. the date on which we have more than $700 million in market value of our common units held by non-affiliates; or

iv. the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period.

We have elected to adopt the reduced disclosure requirements described above, except that we have elected to opt out of the exemption that allows emerging growth companies to extend the transition period for complying with new or revised financial accounting standards.

Ownership Structure

The following table depicts our ownership structure as of December 31, 2014:

Description	Percentage ownership
Ownership by non-affiliates:	
Public common units	41.8%
Southcross Holdings LP's ownership:	
Common units	4.1%
Subordinated units	23.4%
Class B Convertible Units	28.7%
General partner interest	2.0%
Total	**100.0%**

Business Strategy

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time by expanding the capacity and efficiency of our assets and by making selective acquisitions while ensuring the ongoing stability of our business. We expect to achieve this objective by pursuing the following business strategies:

- ***Capitalize on organic growth opportunities, with a focus on high-growth regions such as the Eagle Ford Shale area.*** We intend to continue to evaluate and execute midstream projects involving the gathering, processing, treating, compression and transportation of natural gas and the transportation and fractionation of NGLs that enhance our existing systems as well as to aggregate supply and obtain access to premium markets for that supply. We plan to continue to focus on projects that we expect to increase our total throughput volume and generate attractive returns.

- ***Continue to enhance the profitability of our existing assets.*** We intend to increase the profitability of our existing asset base by identifying new business opportunities and adding new volumes of natural gas supplies to our existing assets. Specifically, we plan to capture incremental processing and NGL fractionation margins from our existing throughput and to undertake additional initiatives to increase gas volumes and enhance utilization of our assets, as well as to continue to enhance cost efficiencies.

- ***Pursue accretive acquisitions of complementary assets.*** We intend to pursue accretive acquisitions that strategically expand or complement our existing asset portfolio. We monitor the marketplace to identify and pursue such acquisitions, with a particular focus on regions with potential for additional near-term development. To identify potential acquisitions of businesses or assets, we seek to utilize our industry knowledge, network of customers and strategic asset base. We intend to pursue acquisition opportunities both independently of and jointly with our Sponsors.
- ***Execute accretive drop downs of complementary assets from Holdings.*** We intend to pursue accretive acquisitions from our parent company, Holdings, which strategically expand or complement our existing asset portfolio, primarily in the Eagle Ford Shale area. However, Holdings is not obligated to execute these drop downs.
- ***Manage our exposure to commodity price risk.*** Because natural gas and NGL prices are volatile, we strive to mitigate the impact of fluctuations in commodity prices and to generate more stable cash flows. We have, and will continue to pursue, a contract portfolio that is heavily weighted towards fixed-fee and fixed-spread contracts, which are not directly sensitive to commodity price levels, while minimizing our direct exposure to commodity price fluctuations. We also will consider other methods of limiting commodity exposure, including the use of derivative instruments, as appropriate.
- ***Maintain sound financial practices to ensure our long-term viability.*** We intend to maintain our commitment to financial discipline, which we believe will serve the long-term interests of our unitholders. Consistent with such approach, we generally intend to fund the long-term capital requirements for expansion projects and acquisitions through a prudent combination of equity and debt capital.

Competitive Strengths

We believe that we are well-positioned to execute our business strategies successfully by capitalizing on the following competitive strengths:

- ***Strategically located asset base.*** The majority of our assets are located in, or within close proximity to, the Eagle Ford Shale area in South Texas, which is one of the most active drilling regions in the U.S. We also operate in Mississippi and Alabama. We believe the high growth potential of our South Texas assets coupled with the established, long-lived nature of our Mississippi and Alabama assets provide us with the opportunity to generate growth over the next several years. In addition, all of our assets have access to major natural gas market areas.
    - *South Texas.* The close proximity of our South Texas system to the Eagle Ford Shale area has allowed us to execute several organic capital projects in the area, to identify additional infrastructure needs adjacent to our existing systems and to make strategic acquisitions in that area, including our acquisition of the TexStar Rich Gas System. Our growth opportunities are impacted primarily by activity levels in our Eagle Ford area. Our Eagle Ford Southcross pipeline catchment area includes multiple prospective production zones, including the Olmos tight sands formation, which overlays the Eagle Ford Shale. Our business activity provides us with relationships with producers in the Eagle Ford Shale region and an understanding of their future development plans and infrastructure needs. In addition, our South Texas systems benefit from access to the large industrial market in and around the Corpus Christi area.
    - *Mississippi and Alabama.* We believe we are a leading service provider in the Mississippi and Alabama regions in which we operate. Our assets provide critical supply to our industrial, commercial and power generation customers and the wholesale markets via intrastate and interstate pipeline interconnects. Several of the large, gas-fired power plants across the southern portion of Mississippi access their primary source of natural gas through our system.

- ***Reliable cash flows underpinned by long-term, fixed-fee and fixed-spread contracts.*** We provide our services primarily under fixed-fee and fixed-spread contracts, which help to promote cash flow reliability and minimize our direct exposure to commodity price fluctuations.
- ***Integrated midstream value chain.*** We provide a comprehensive package of services to natural gas producers and customers including natural gas gathering, processing, treating, compression and transportation and NGL fractionation and transportation. We believe our ability to move natural gas and NGLs from the wellhead to market provides us with several advantages in competing for new supplies of natural gas. Specifically, the integrated nature of our business allows us to provide multiple services related to a single supply of natural gas and take advantage of incremental opportunities that present themselves along the value chain. Providing multiple services to customers also gives us a better understanding of each customer's needs and the marketplace. In addition to the advantages with our producers and customers, our ability to source and transport natural gas to market also allows us to satisfy our commercial and industrial customers' demand for natural gas. We believe all of these factors provide a competitive advantage relative to companies which do not offer this range of midstream services.
- ***Experienced and incentivized management and operating teams.*** Our senior executives have worked in several energy companies. Our executive officers have extensive experience in building, acquiring and managing midstream and other energy assets and are focused on optimizing our existing business and expanding our operations through disciplined development and accretive acquisitions. Many of our field operating managers and supervisors have long-standing experience operating our assets.
- ***Supportive Sponsors with significant industry expertise.*** Our Sponsors are the principal owners of Holdings, the owner of our General Partner and the holder of an approximate 57.4% limited partnership interest in us, and have substantial experience as private equity investors in the energy and midstream sectors. Our Sponsors' investment professionals have deep experience in identifying, evaluating, negotiating and financing acquisitions and investments in the midstream sector. We believe that our Sponsors provide us with strategic guidance, financial expertise and potential capital support that enhance our ability to grow our asset base and cash flow.

Our Assets and Operations

Our assets consist of gathering systems, intrastate pipelines, four natural gas processing plants, two fractionation facilities and pipelines. Our operations are managed as and presented in one reportable segment.

The following tables provide information regarding our assets as of and for the year ended December 31, 2014:

Gathering systems and intrastate pipelines	As of December 31, 2014	Year Ended December 31, 2014
	Miles	Average throughput volumes of natural gas (MMBtu/d)
South Texas	1,866	689,180
Mississippi/Alabama	1,139	195,079
Total	3,005	884,259

Processing plants	As of December 31, 2014	Year Ended December 31, 2014
	Approximate design of gas processing capacity (Mcf/d)	Average volume of processed gas (MMBtu/d)
Gregory	135,000	72,859
Conroe	50,000	27,329
Woodsboro	200,000	189,021
Lone Star	300,000	153,269
Total	685,000	442,478

Fractionation plants	As of December 31, 2014	Year Ended December 31, 2014
	Approximate design of fractionation capacity (Bbls/d)	Average volume of NGLs sold from output (Bbls/d)
Gregory	4,800	1,618
Bonnie View	22,500	15,551
Total	27,300	17,169

As a result of the TexStar Rich Gas System Transaction, we acquired equity interests in three joint ventures, including T2 Eagle Ford Gathering Company LLC (“T2 Eagle Ford”), T2 LaSalle Gathering Company LLC (“T2 LaSalle”) and T2 EF Cogeneration Holdings LLC (“T2 Cogen”), which operate a pipeline and cogeneration facility located in South Texas. We indirectly have a 50% interest in T2 Eagle Ford, a 50% interest in T2 Cogen and a 25% interest in T2 LaSalle. T2 Cogen operates two gas powered turbines that buy fuel from related parties and charges such parties based on monthly electrical activity. The following table provides information regarding our pipeline joint venture investments, T2 Eagle Ford and T2 LaSalle, for the year ended December 31, 2014:

	As of December 31, 2014		
Joint venture pipelines	Miles	Leased Capacity	Average throughput volumes of natural gas (MMBtu/d)[(1)]
Dimmit	46	50%	64,499
LaSalle	58	25%	158,111
Choke Canyon	72	50%	214,088
Residue	57	50%	166,226
Total	233		

(1) Average throughput volumes of natural gas calculated for the entire year ended December 31, 2014.

We derive revenue primarily from fixed-fee and fixed-spread arrangements. For the year ended December 31, 2014, our fixed-fee and fixed-spread arrangements accounted for approximately 77% of our gross operating margin. Our contracts vary in duration from one month to several years and the duration and pricing of our contracts vary depending upon several factors, including our competitive position, our acceptance of risks associated with longer-term contracts, and our desire to recoup over the term of a contract any capital expenditures that we are required to incur in order to provide service to our customers.

We continually seek new sources of natural gas supply and end use markets to increase the gas throughput volume on our gathering and pipeline systems and through our processing plants.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. Our NGL products and the demand for these products are affected as follows:

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

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

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

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

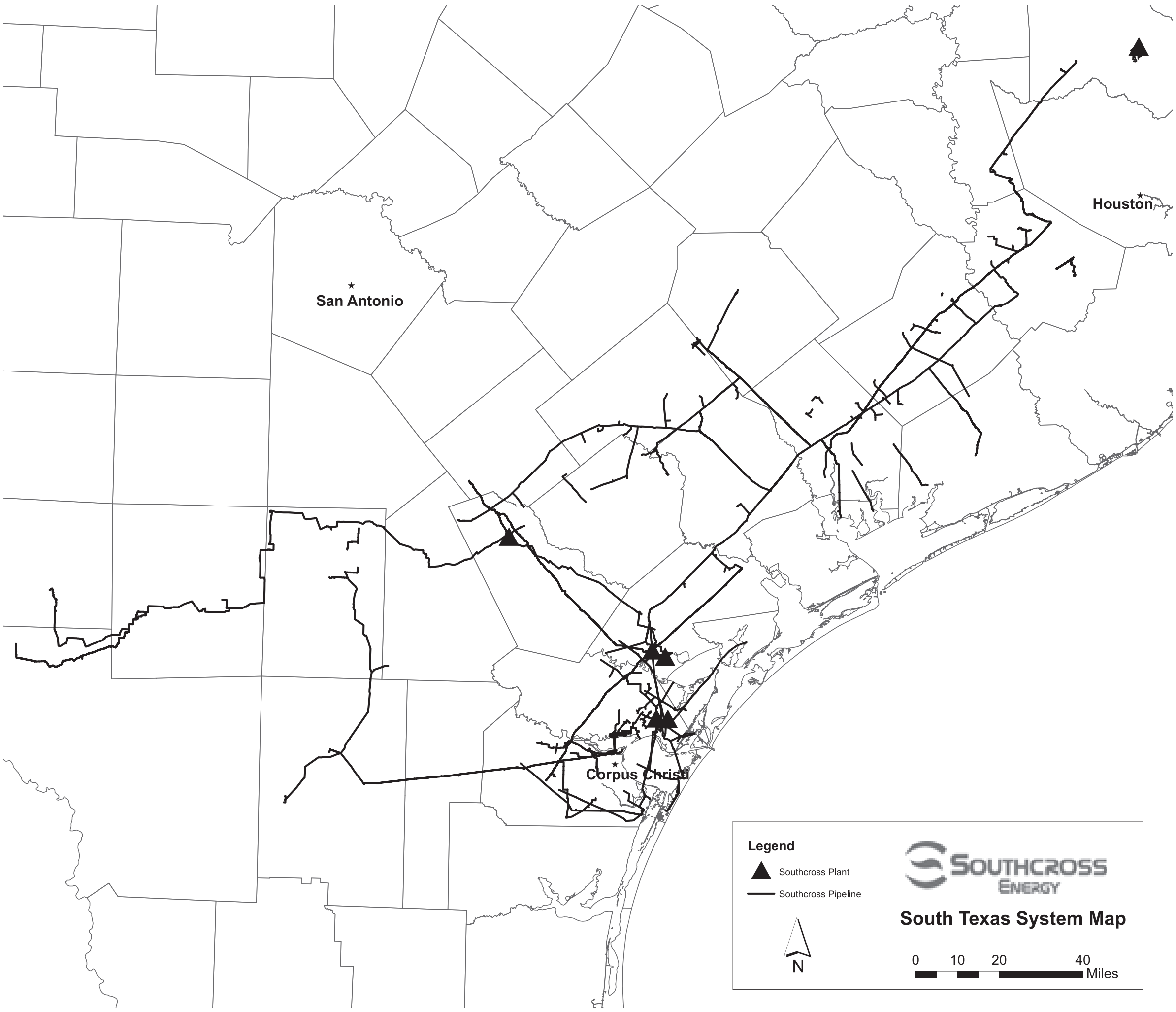
- ***Natural Gasoline.*** Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene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

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

South Texas

The assets in our South Texas region are located between Conroe and Webb and Dimmitt Counties near the Texas-Mexico border. As of December 31, 2014, these assets consisted of approximately 1,866 miles of pipeline ranging in diameter from 2 to 24 inches, our Woodsboro processing plant, our Bonnie View NGL fractionation facility, our Gregory processing plant and NGL fractionation facility, our Lone Star processing plant and our Conroe gathering system and its associated processing plant.

The majority of our pipelines in South Texas feed rich gas from multiple producing fields, including the Eagle Ford Shale, to our processing and NGL fractionation facilities at Lone Star, Woodsboro, Gregory and Conroe. The residue gas pipelines from our processing plants and the remaining pipelines in lean gas service in South Texas are used to serve multiple industrial and electric generation customers, and to deliver gas to a number of intrastate and interstate pipelines.



Our Woodsboro processing plant is a 200 MMcf/d cryogenic processing plant located in Refugio County, Texas. Our Bonnie View NGL fractionation plant, also in Refugio County, Texas has a capacity of 22,500 Bbls/d.

Our Lone Star processing plant is a 300 MMcf/d cryogenic processing plant located in Bee County, Texas, and was acquired from TexStar in August 2014. The plant is interconnected with other South Texas rich gas supply basins via our Bee Line pipeline which was placed into service in 2013.

Our Gregory processing plant is a cryogenic natural gas plant comprised of two units collectively having a total capacity of 135 MMcf/d. This plant processes natural gas from both a local gathering system and from sources elsewhere on our South Texas pipeline systems. NGLs produced at our Gregory processing plant are typically fractionated in our NGL fractionator located on the same site. The Gregory NGL fractionation plant has a total capacity of 4,800 Bbls/d.

Purity ethane produced from our Gregory and Bonnie View facilities is shipped via pipeline to a subsidiary of The Dow Chemical Company. During 2013, Trafigura AG began purchasing NGLs produced from our Bonnie View and Gregory facilities.

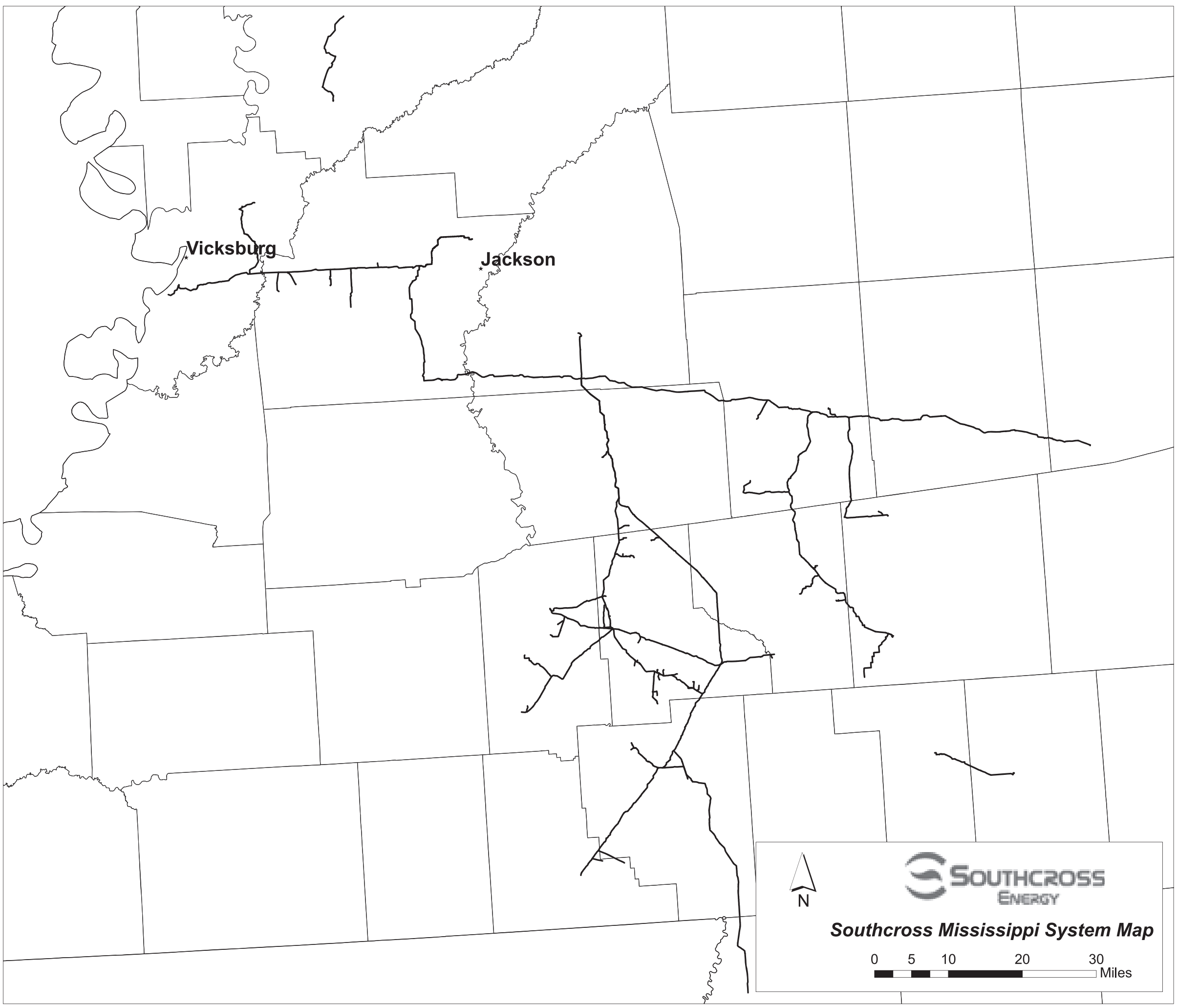
On January 26, 2013, as the turnaround maintenance at our Gregory processing and NGL fractionation plants was nearing completion, we experienced a fire at the facility. Damage was limited to a small portion of the facility and we completed repairs and resumed operations during April 2013. We recovered $1.0 million in 2013, $3.9 million in 2014 and $0.5 million in January 2015 for this loss under our insurance policies. We also incurred $0.3 million in additional expenses related to our insurance deductible.

On January 20, 2015, our Gregory processing plant experienced a fire which caused damage to one of our two processing plants, taking 80 MMcf/d of processing capacity temporarily out of service. In February 2015, we brought 55 MMcf/d back on-line. We do not expect the cost to repair the fire damage to significantly exceed our insurance deductible of $0.5 million, nor do we expect the downtime while the plant is being repaired to have a material impact on our financial results.

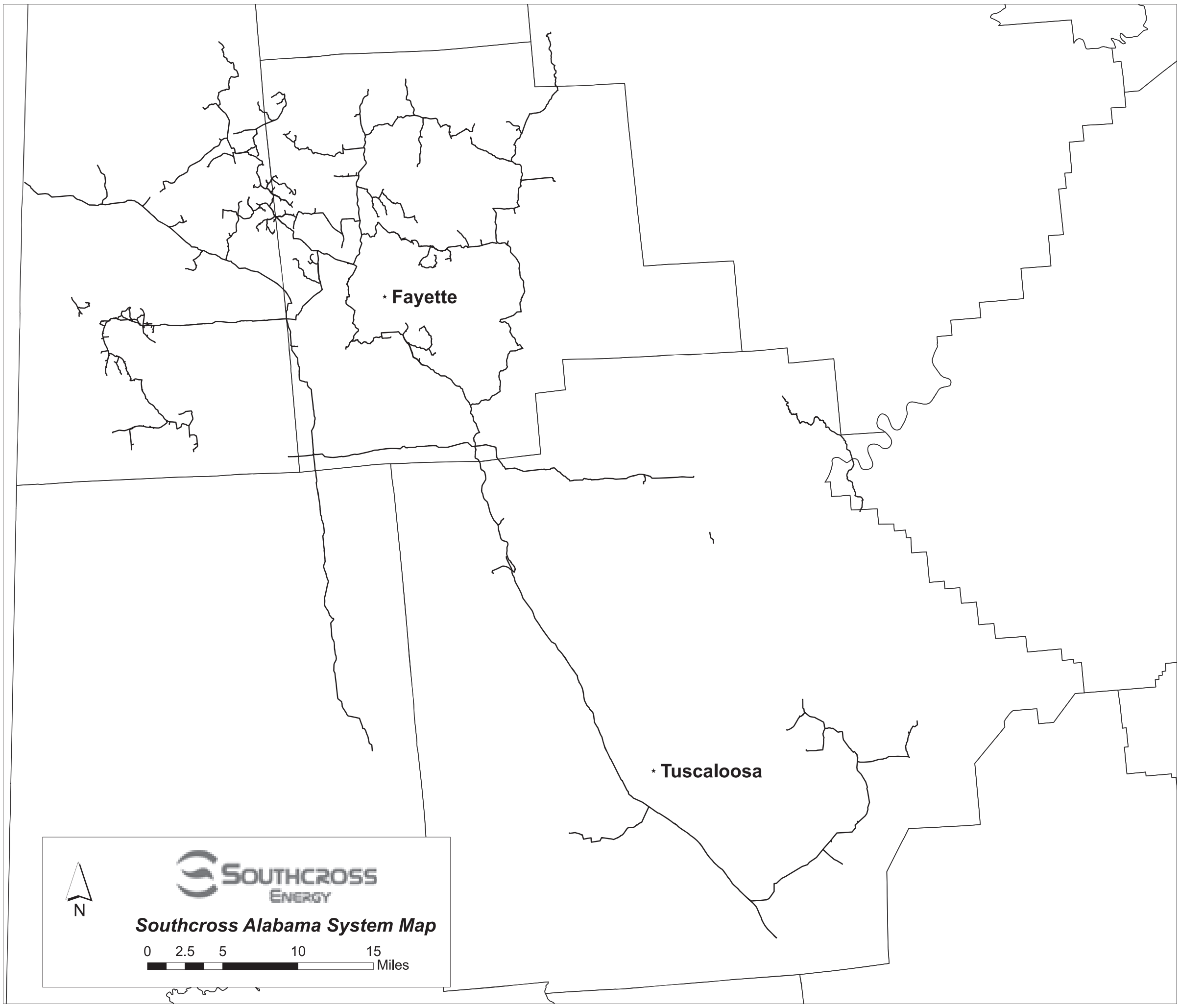
Our Conroe processing plant and gathering system is a 50 MMcf/d cryogenic natural gas plant. The processing plant and gathering system operate together on a stand-alone basis north of Houston in Montgomery County, Texas to gather, process, sell and recycle natural gas. We have fixed-fee processing contracts with producers, under which the majority of the residue gas from the Conroe plant is returned to the producers for gas lift purposes. We sell the remaining residue gas and NGLs to unaffiliated parties.

Mississippi and Alabama

The assets in our Mississippi region are located principally in the southern half of the state and comprise the largest intrastate pipeline system in Mississippi. The Mississippi assets consist of approximately 625 miles of pipeline, ranging in diameter from 2 to 20 inches with an estimated design capacity of 345 MMcf/d, and two treating plants. Our system throughput volumes in Mississippi are affected by both on-system gas production volumes and customers' demand for gas. The system has the capability to receive natural gas from three unaffiliated interstate pipelines—Southeast Supply Header, Southern Natural Gas Company (SONAT) and Texas Eastern—to supplement supply on the system or to market gas off the system.



The assets in our Alabama region are located in northwest and central Alabama and consist of 514 miles of natural gas gathering and transmission pipelines ranging from 2 to 16 inches in diameter with an estimated design capacity of 375 MMcf/d. The primary gas supply to the system is coal bed methane gas from the Black Warrior Basin with incremental volumes gathered from conventional gas wells.



Competition

The natural gas gathering, compression, processing, transportation and marketing business and the NGL fractionation business are highly competitive. Our competitors include other midstream companies, producers and intrastate and interstate pipelines. Competition for natural gas volumes is based primarily on commercial terms, reliability, service levels, flexibility, access to markets, location, available capacity, connection costs and fuel efficiencies. Our principal competitors are DCP Midstream LLC, Energy Transfer Partners, L.P., Enterprise Products Partners LP, Boardwalk Pipeline Partners, LP, Kinder Morgan Inc., Spectra Energy Partners, LP and Atlas Pipeline Partners, LP.

In addition to competing for natural gas supply volumes, we face competition for customer markets in selling residue gas and NGLs. Competition is based primarily on the proximity of pipelines to the markets, price and assurance of supply.

Customers and Concentration of Credit Risk

Our markets are in Texas, Alabama and Mississippi and we have a concentration of trade accounts receivable due from customers engaged in the purchase and sale of natural gas and NGL products, and other services. These concentrations of customers may affect our overall credit risk as these customers may be similarly affected by changes in economic, regulatory or other factors. We analyze customers' historical financial and operational information prior to extending credit and we monitor creditworthiness on a periodic basis.

Our top ten customers accounted for 63.9% of our revenue for the year ended December 31, 2014, including one customer, Trafigura AG, which accounted for 13.7% of our 2014 revenue.

Governmental Regulation

We are subject to regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (the "PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968 (the "NGPSA"), and the Pipeline Safety Improvement Act of 2002 (the "PSIA"), which was 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. crude oil and natural gas transmission pipelines 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, reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

PHMSA issued a rule that increased the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after January 3, 2012 to $200,000 per violation per day, with a maximum of $2,000,000 for a series of violations. 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 and has also published advanced notice of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including gathering lines. The PHMSA recently published an advisory bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. We have performed hydrotests of our facilities to establish the maximum allowable operating pressure and do not expect that any final rulemaking by PHMSA regarding verification of maximum allowable operating pressure would materially affect our operations or revenue. We believe our records relating to allowable maximum operating pressure to be reliable, traceable, verifiable and complete. Additionally, the National Transportation Safety Board has recently recommended that the PHMSA make a number of changes to its rules, including removing an exemption from most safety inspections for natural gas pipelines installed before 1970.

While we cannot predict the outcome of 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 and gathering lines not previously subject to such requirements. Further 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, but we regularly inspect our pipelines and third parties assist us in interpreting the results of the inspections.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most states are certified by the U.S. Department of Transportation (the "DOT") to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our natural gas and natural gas products 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 (the "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 Emergency Planning and Community Right-to-Know Act (the "EPCRA") 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 regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling points without the benefit of chilling or refrigeration are exempt. 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.

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

- The Environmental Protection Agency's (the "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.

Intrastate Pipelines

Our transmission lines are subject to state regulation of rates and terms of service. In Texas, the regulatory system allows rates to be negotiated on a customer-by-customer basis and are subject to a complaint-based review process. In rare circumstances, as allowed by statute, regulators may initiate a rate review. Although Texas does not have an "open access" requirement, there is a "non-discriminatory access" requirement, which is subject to a complaint-based review. In Mississippi and Alabama, the regulatory systems allow special contracts that are negotiated on a customer-by-customer basis for approval by the applicable state commission.

Section 311 Pipelines

Intrastate transportation of natural gas is largely regulated by the state in which such transportation takes place. Several of our intrastate pipeline subsidiaries, Southcross CCNG Transmission Ltd., Southcross Gulf Coast Transmission Ltd., Southcross Mississippi Pipeline, L.P., TexStar Transmission, L.P., Southcross Nueces Pipelines LLC and Southcross Alabama Pipeline LLC, also provide interstate transportation services. The rates, terms and conditions of such services are subject to the Federal Energy Regulatory Commission (the "FERC") jurisdiction under Section 311 of the Natural Gas Policy Act ("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 an interstate natural gas pipeline or a local distribution company or LDC served by an interstate natural gas pipeline. 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 rates under Section 311 approved by the FERC are maximum rates and we may negotiate at or below such rates. Currently, the FERC reviews our maximum rates every five years and such maximum rates may increase or decrease as a result of such reviews. Presently, we are awaiting the FERC approval of rates for one of our subsidiaries which filed a petition in early December 2014. Our next subsidiary required to file a petition for the FERC's rate approval will file by April 2015. The terms and conditions of service set forth in the intrastate pipeline's statement of operating conditions are also subject to the FERC's review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and/or 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 or sanctions.

Hinshaw Pipelines

Similar to intrastate pipelines, Hinshaw pipelines, by definition, also operate within a single state. We have a Mississippi pipeline segment that is categorized as a Hinshaw pipeline. Also, similar to pipelines operating under Section 311 of the NGPA, Hinshaw pipelines can receive gas from outside their state without becoming subject to the FERC's Natural Gas Act ("NGA") jurisdiction. Specifically, Section 1(c) of the NGA exempts from the FERC's NGA jurisdiction those pipelines that transport gas in interstate commerce if (1) they receive natural gas at or within the boundary of a state, (2) all the gas is consumed within that state and (3) the pipeline is regulated by a state commission. Following the enactment of the NGPA, the FERC issued Order No. 63 authorizing Hinshaw pipelines to apply for authorization to transport natural gas in interstate commerce in the same manner as intrastate pipelines operating pursuant to Section 311 of the NGPA. Hinshaw pipelines frequently operate pursuant to blanket certificates to provide transportation and sales service under the FERC's regulations.

Historically, the FERC did not require intrastate and Hinshaw pipelines to meet the same rigorous transactional reporting guidelines as interstate pipelines. However, as discussed below, in May 2010, the FERC issued Order No. 735, which increases the FERC regulation of certain intrastate and Hinshaw pipelines.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. Although the FERC has not made a formal determination with respect to all of our facilities we believe to be gathering facilities, we believe that our natural gas gathering pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to the FERC jurisdiction. The distinction between the FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities 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 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 have been no adverse effects to our systems due to these regulations.

Market Behavior Rules; Reporting Requirements

On August 8, 2005, Congress enacted the Energy Policy Act of 2005 (“the EPAct 2005”). Among other matters, the EPAct 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by the FERC and, furthermore, provides the FERC with additional civil penalty authority. On January 19, 2006, the 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 the FERC or the purchase or sale of transportation services subject to the jurisdiction of the FERC to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The 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 the 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 the 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, the 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. In addition, the Commodities Futures Trading Commission (the “CFTC”) is directed under the Commodities Exchange Act (the “CEA”) to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of one million dollars ($1,000,000) or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

The EPAct 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, the 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, the 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 the FERC's jurisdiction, to provide by May 1 of each year an annual report to the 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 the FERC's policy statement on price reporting. In June 2010, the FERC issued the last of its three orders on rehearing and clarification 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 the 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 FERC'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.

On November 15, 2012, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether to amend its regulations under the natural gas market transparency provisions of Section 23 of the NGA, as adopted by EPAct 2005, to consider the extent to which quarterly reporting of every natural gas transaction within the FERC's NGA jurisdiction that entails physical delivery for the next day or next month would provide useful information for improving natural gas market transparency. The FERC has yet to issue an order.

State Utility Regulation

Some of our operations in Texas are specifically subject to the Texas Gas Utility Regulatory Act, as implemented by the Railroad Commission of Texas ("RRC"). Generally, the RRC has authority to ensure that rates charged for natural gas sales or transportation services are just and reasonable. Our gas utilities, Southcross CCNG Gathering Ltd., Southcross CCNG Transmission Ltd. and Southcross Gulf Coast Transmission Ltd., Southcross Nueces Pipelines LLC, FL Rich Gas Utility and TexStar Transmission, L.P. are required to file gas tariffs and Southcross NGL Pipeline Ltd. has filed a NGL tariff with the RRC.

In Mississippi, the Mississippi Public Service Commission considers Southcross Mississippi Industrial Gas Sales, L.P. ("MIGS") a utility and it is necessary to get contract approval for negotiated contracts. MIGS is a transporter to an end-user, the Leaf River Cellulose Plant, which is located within Mississippi.

In Alabama, the Alabama Public Service Commission ("APSC") requires a gas utility to file "special negotiated contracts" with the APSC for approval. This requirement includes our Southcross Alabama Pipeline LLC ("SAP LLC") which now includes the assets of Southcross Alabama Gathering System, L.P. which was merged with and into SAP LLC on December 1, 2014.

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.

Sales of Natural Gas and NGLs

Historically, the transportation and sale or resale of natural gas in interstate commerce has been regulated by the FERC under the NGA, the NGPA and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

The price at which we sell natural gas is currently not 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. 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 currently not 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.

Anti-terrorism Measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security (the “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 establishes chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. In addition, in August 2014, DHS issued an advanced notice of proposed rulemaking designed to identify ways to make the Chemical Facility Anti-Terrorism Standards program more effective. 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 (the Gregory, Conroe and Woodsboro plants) 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 determined that none of the facilities are considered high-risk chemical facilities.

Cyber Security Measures

While we are currently not subject to governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered in the U.S. Congress and by U.S. Executive Branch departments and agencies, including the DHS, and we may become subject to such standards in the future. Currently, we are implementing our own cyber security programs and protocols; however, we cannot guarantee their effectiveness. A significant cyber-attack could have a material effect on our operations and those of our customers.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for natural gas gathering, processing, treating, compression and transportation, and for NGL fractionation and transportation services are 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 or imposing additional costs on our operations;
- managing or otherwise regulating the way we handle and secure toxic, reactive, flammable or explosive materials to prevent or minimize the release of such materials;
- 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 or third-party operations; and
- enjoining the operations of facilities deemed to be in non-compliance with permits issued pursuant to or permit requirements imposed by 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, process, treat, compress and transport natural gas and fractionate and transport NGLs. We cannot assure you, 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 cleanup 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 (the "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. Moreover, from time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for non-hazardous wastes, including natural gas wastes. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses or otherwise impose limits or restrictions on our operations or those of our customers.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated 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 1991, the EPA adopted regulations under the Oil Pollution Act (the "OPA"). These oil pollution prevention regulations, as amended several times since their original adoption, 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 U.S. 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 none of our facilities is 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 (the "CAA"), and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations and processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we are in substantial compliance with these requirements. We and our customers 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.

On January 30, 2013, the EPA finalized amendments to new regulations under the CAA to control emissions of hazardous air pollutants from stationary reciprocating internal combustion engines and stationary internal combustion engines. Subsequently, the EPA received three petitions for reconsideration of the final rules. On September 5, 2013, EPA agreed to reconsider the rules with respect to only the three issues raised in the petitions and requested public comment. As of the new effective date of November 19, 2014, we believe we are in full compliance with the rule. The scope of applicability for most of our engines is the requirement to follow a prescribed maintenance plan or comply with already existing New Source Performance Standard JJJJ. The few engines we do have that are subject to the control and compliance provisions of National Emission Standards for Hazardous Air Pollutants Standard ZZZZ are new engines which meet the emissions limitations therein. We believe we are also in compliance with all procedures within this regulation.

On April 17, 2012, the EPA approved final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. This rule addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. For new or reworked hydraulically-fractured gas wells, the final rule requires controlling emissions through flaring until 2015, when the rule requires the use of reduced emission, or “green”, completions. The rule also established specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. On August 5, 2013, the EPA finalized updates to the 2012 performance standards for emissions of volatile organic compounds (“VOCs”) from storage tanks used in oil and natural gas production and transmission, which, among other things, adjusted reporting requirements and phased in the date by which storage tanks must install VOC controls. Compliance with these rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Water Discharges

The Federal Water Pollution Control Act (the “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 impose requirements affecting our ability 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 under the Clean Water Act and state counterparts 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 is 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 believe that our facilities will not be materially adversely affected by such requirements.

Endangered Species

The Endangered Species Act (the "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 or limit future development activity in the affected areas.

National Environmental Policy Act

The National Environmental Policy Act (the "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 impact significantly the environment requires review under NEPA and, as a result, many activities requiring the 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 and, on March 12, 2012, issued final guidance that 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" or "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 U.S. 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 U.S. submitted a greenhouse gas emission reduction target of 17% by 2020 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 (the "Court") determined that GHG emissions fall within the federal 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 CAA. On June 23, 2014 the Court ruled that (1) the EPA exceeded its statutory authority when it interpreted the CAA to require Prevention of Significant Deterioration ("PSD") and Title V permitting for stationary sources based on their GHG emissions, (2) the EPA may not treat GHGs as a pollutant for purposes of defining a "major emitting facility" (or a "modification" thereof) in the PSD context or a "major source" in the Title V context, and (3) the EPA may, however, continue to treat GHGs as "a pollutant subject to regulation under this chapter" for purposes of requiring Best Available Control Technology ("BACT") for "anyway" sources. This means that the facilities we typically operate, which are not PSD or Title V major sources for non-GHG emissions, do not and should not have required PSD or Title V permitting based solely on their GHG emissions exceeding the major source threshold.

In addition, on September 22, 2009, the EPA issued a final rule requiring the monitoring and 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 Gregory, Woodsboro, Bonnie View, Conroe, Lone Star and El Dorado facilities are or will be required to report under this rule. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, and which has been repeatedly revised and amended with respect to such matters as technical corrections, business confidentiality and deadlines for compliance, requires annual reporting of greenhouse gas emissions by regulated facilities to the EPA. We have submitted the reports required under this rule on a timely basis and have adopted procedures for future required reporting.

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. Moreover, while the Court held in its June 2011 decision in *American Electric Power Co., Inc. v. Connecticut* that with respect to claims concerning GHG emissions, the federal common law of nuisance was displaced by the federal CAA, the Court left open the question whether tort claims against GHG emissions sources alleging property damage may proceed under state common law. There thus remains some litigation risk for such claims. 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, 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 GHG 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.

Employees

Currently, we do not have any employees. We rely solely on officers and employees of our General Partner to operate and manage our business. Our General Partner employed 314 employees as of December 31, 2014. None of these employees are covered by collective bargaining agreements, and our General Partner considers its employee relations to be good.

Available Information, "Lead Director" and Corporate Governance Documents

Available Information

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to such reports, as well as other documents electronically with the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). From time-to-time, we also may file registration and related statements pertaining to equity or debt offerings. We provide access free of charge to all of these materials, as soon as reasonably practicable after such materials are filed with, or furnished to the SEC, on our website located at *www.southcrossenergy.com*.

The public may obtain such reports from the SEC's website at *www.sec.gov*. The public may also read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-(800) SEC-0330.

Interested parties may communicate directly with the independent directors of our General Partner by submitting a communication in an envelope marked "Confidential" addressed to the "Independent Members of the Board of Directors" in care of Jerry W. Pinkerton, as our current "Lead Director," or such other director designated as the "Lead Director" under the Corporate Governance Guidelines adopted by our General Partner and disclosed in any future public filings with the SEC, and delivering it to 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201.

Lead Director

In accordance with the Corporate Governance Guidelines adopted by our General Partner, Jerry W. Pinkerton is our "Lead Director" responsible for chairing the executive sessions required to be held by our General Partner's non-management directors. The Corporate Governance Guidelines permit the Chairman of the board of directors of our General Partner to designate another independent director to lead such meetings as the "Lead Director."

Corporate Governance Documents

We make available free of charge, within the "Investors" section of our website at *www.southcrossenergy.com*, and in print to any unitholder who so requests, our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Audit Committee Charter and Compensation Committee Charter. Requests for print copies may be directed to investorrelations@southcrossenergy.com or to: Investor Relations, Southcross Energy Partners, L.P., 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201, or telephone (214) 979-3720. We will post on our website all waivers to or amendments of the Code of Business Conduct and Ethics, that are required to be disclosed by applicable law and the NYSE's Corporate Governance Listing Standards. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. Risk Factors

You should carefully consider the following risk factors, together with all of the other information included in this report, when deciding whether to invest in us. Limited partner interests 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 a similar business. You should be aware that the occurrence of any of the events described in this report could have a material adverse effect on our business, financial condition, results of operations and cash flows. In such event, we may be unable to make distributions to our unitholders and the trading price of our common units could decline.

Risks Related to Our Business

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, or any distribution, to our unitholders.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volume of natural gas we gather, process, treat, compress and transport and the volume of NGLs we fractionate and transport;
- the level of production of, and the demand for, crude oil, natural gas and NGLs and the market prices of crude oil, natural gas and NGLs;
- damage to pipelines, facilities, plants, related equipment and surrounding properties caused by hurricanes, earthquakes, floods, fires, severe weather, explosions and other natural disasters and acts of terrorism including damage to third-party pipelines or facilities upon which we rely for transportation and processing services;
- outages at the processing or NGL fractionation facilities owned by us or third parties, whether caused by mechanical failure resulting from maintenance, construction or otherwise;
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise;
- prevailing economic and market conditions;
- realized prices received for natural gas and NGLs;
- fixed-fees associated with our services;
- 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, general and administrative costs; and
- regulatory action affecting the supply of, or demand for, natural gas, the maximum transportation rates we can charge on our pipelines, our existing contracts, our operating costs or our operating flexibility.

In addition, the actual amount of cash we will have available for distributions will depend on other factors, some of which are beyond our control, 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 in part on producers growing production and replacing declining production and also on our ability to obtain new sources of natural gas. Any decrease in the volumes of natural gas that we gather, compress, process, treat or transport or in the volumes of NGLs that we fractionate or transport could adversely affect our business and operating results.

The natural gas volumes that support our business depend on the level of production from natural gas wells connected to our systems, which may be less than expected and will naturally decline over time. As a result, our cash flows associated with these wells also will 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, (ii) our ability to compete for volumes from successful new wells and (iii) our ability to compete successfully for volumes from sources connected to other pipelines.

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

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

Fluctuations in energy prices can also greatly affect the development of crude oil and natural gas reserves. Drilling and production activity generally decreases as natural gas, crude oil or NGL prices decrease. Declines in natural gas, crude oil or NGL prices could have a negative impact on exploration, development and production activity, and sustained low prices could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation could lead to reduced utilization of our assets.

Lower crude oil prices commencing in the second half of 2014 have given producers less incentive to expand exploration, development and production. Given the historical volatility of crude oil prices, there remains a risk that prices could further deteriorate due to increased domestic production, slowing economic growth rates in various global regions and/or the potential for significant supply and demand imbalances.

As with falling crude oil prices, declines in natural gas or NGL prices could have a negative impact on exploration, development and production activity, and sustained low prices of any of these commodities could lead to a material decrease in such activity. Certain of our producers and other suppliers are tied to crude oil wells, and any sustained reduction in exploration or production activity in our areas of operation, whether related to crude oil, natural gas or NGLs, or a combination of them, could lead to reduced utilization of our assets, including the volume of natural gas flowing on our system.

Because of these and other factors, even if natural gas and liquid 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, those reductions could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

We do not obtain independent evaluations of natural gas and liquid 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 obtain independent evaluations of the natural gas reserves connected to our systems on a regular or ongoing basis. Accordingly, we do 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 success depends on drilling activity by customers and our ability to attract and maintain customers in a limited number of geographic areas.

A significant portion of our assets is located in the Eagle Ford Shale area, and we intend to focus our future capital expenditures largely on developing our business in this area. As a result, our financial condition, results of operations and cash flows are significantly dependent upon the demand for our services in this area. Due to our focus on this area, an adverse development in natural gas production from this area, such as decreased development or production activity, would have a significantly greater impact on our financial condition and results of operations than if we spread expenditures more evenly over a wider geographic area.

Our failure to effectively execute our major development projects could result in delays and/or cost over-runs, limitations on our growth and negative effects on our operating results, liquidity and financial position.

We are engaged in the planning and construction of several major development projects, some of which will take a number of months before commercial operation. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Also, legislative or regulatory intervention may create limits or prohibit our ability to perform desired capital projects. Delays in the completion of these projects could have a material adverse effect on our business, financial condition, results of operations and liquidity. Estimating the timing and expenditures related to these development projects is complex and subject to variables that can increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and capital position could be adversely affected. This level of development activity requires effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls.

Energy prices are volatile, and a change in these prices in absolute terms, or an adverse change in energy prices, particularly natural gas and NGLs relative to one another, could adversely affect our gross operating margin and cash flow and our ability to make cash distributions to our unitholders.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas, NGLs and other commodities have been extremely volatile, and we expect this volatility to continue. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration.

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

- worldwide economic conditions;
- worldwide political events, including actions taken by foreign oil and natural gas producing nations;
- worldwide weather events and conditions, including natural disasters and seasonal changes;
- the levels of domestic production and consumer demand;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation;
- fluctuations in demand from electric power generators and industrial customers; and
- the anticipated future prices of crude oil, natural gas, NGLs and other commodities.

Our exposure to direct commodity price risk and volatility in costs to market products may vary.

We currently generate a large portion of our revenues pursuant to fixed-fee contracts under which we are paid based on the volumes of natural gas that we gather, process, treat, compress and transport and the volumes of NGLs we fractionate and transport, rather than the value of the underlying natural gas or NGLs. Consequently, this portion of our existing operations and cash flows have limited direct exposure to commodity price levels. Although we intend to enter into similar fixed-fee contracts with new customers in the future, our efforts to obtain such contractual terms may not be successful. We may acquire or develop additional midstream assets or change the arrangements under which we process our volumes. These changes may also impact our transportation and gathering costs in a manner that increases our exposure to commodity price risk. Extended or future exposure to the volatility of crude oil and natural gas prices could have a material adverse effect on our business, results of operations and financial condition and our ability to make distributions.

In addition, another large portion of our revenues is generated pursuant to fixed-spread contracts under which we strive to buy and sell equal volumes of natural gas and NGLs at prices based upon the same index price of the commodity. Our ability to do this is based upon a number of factors, including willingness of customers to accept the same index as a basis, physical differences in geography, product specifications and ability to market products at the anticipated differential from the pricing index.

Unexpected volume changes due to production variability or to gathering, plant or pipeline system disruptions may increase our exposure to commodity price movements.

We sell processed natural gas to third parties at plant tailgates, pipeline pooling points or at inlet meters to the sites of industrial and utility customers. These sales may be interrupted by disruptions to volumes anywhere along the system. We attempt to balance sales with volumes supplied, but unexpected volume variations due to production variability or to gathering, plant or pipeline system disruptions may expose us to volume imbalances which, in conjunction with movements in commodity prices, could materially impact our income from operations and cash flow.

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 others.

We are exposed to fluctuations in the price of natural gas through volumes sold pursuant to commodity-sensitive arrangements and, to a lesser extent, through volumes sold pursuant to our fixed-spread contracts.

In order to mitigate our direct commodity price exposure, we typically 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. 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 operating margin and cash flows.

Although we enter into back-to-back purchases and sales of natural gas in our fixed-spread contracts in which we purchase natural gas from producers or suppliers at receipt points on our systems and simultaneously sell a similar volume of natural gas at delivery points on our systems, we may not be able to mitigate all exposure to commodity price risks. 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 operating margin and cash flows.

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

We compete with other similarly sized midstream companies in our areas of operation. Some of our competitors are large companies that have greater financial, managerial and other resources than we do. In addition, some of our competitors have assets in closer proximity to natural gas supplies and have available idle capacity in existing assets that would not require new capital investments for use. Our competitors may expand or construct gathering, compression, treating, processing or transportation systems or NGL fractionation facilities 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 or NGL fractionation facilities 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.

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

We gather, purchase, process, treat, compress, transport and sell most of the natural gas and NGLs on our systems under contracts with terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. 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 operating margin and cash flows could decline and our ability to make cash distributions to our unitholders could be materially and adversely affected.

We depend on a relatively limited number of customers for a significant portion of our revenues. The loss of, or material nonpayment or nonperformance by, any one or more of these customers could adversely affect our ability to make cash distributions to our unitholders.

A significant percentage of our revenue is attributable to a relatively limited number of customers. Our top ten customers accounted for 63.9% of our revenue for the year ended December 31, 2014, including one customer that accounted for 13.7% of our revenue for that period. We have gathering, processing, transportation and/or sales contracts with each of these customers of varying duration and commercial terms. If we are unable to renew our contracts 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 addition, some of our customers may have material financial and liquidity issues or may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better capitalized companies. Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our revenue, gross operating margin, cash flows and our ability to make cash distributions to our unitholders. In any of these situations, our revenue, gross operating margin, 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 limited number of customers for a substantial portion of our revenue.

If third-party pipelines, other midstream facilities or purchasers of our products 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 and NGL quality requirements of such pipelines or facilities, our gross operating margin, cash flow and our ability to make distributions to our unitholders could be adversely affected.

Our natural gas gathering and transportation pipelines, NGL pipelines and processing facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of such third-party pipelines, processing plants, facilities of purchasers of our products and other midstream facilities is not within our control. These pipelines and 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 natural disasters or other operational hazards. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our gross operating margin, cash flow and our ability to make cash distributions to our unitholders could be adversely affected.

Significant portions of our pipeline systems and processing plants 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 and processing and treating plants that could have a material adverse effect on our business and operating results.

Significant portions of our pipeline systems and processing plants have been in service for many decades. Our executive management team has a limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems of which our executive management team may be unaware 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.

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, including any interruption of our operations as a result of such accident or event, or if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, our operations and financial results could be adversely affected.

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

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;

- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of human error, the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in interruptions, 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. 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.

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 affected 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 is affected, in part, by 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 cash 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 because our Credit Facility restricts us from making acquisitions, (iii) outbid by competitors or (iv) for any other reason, then our future growth and ability to increase cash distributions could 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;
- the risk that natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- an inability to integrate successfully the assets or businesses we acquire, particularly given the relatively small size of our management team and their limited history with our assets;
- coordinating geographically disparate organizations, systems and facilities;
- 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 growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow.

We continuously consider and enter into discussions regarding potential acquisitions or growth capital expenditures. Any limitations on our access to new capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire strategic and accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, including our then current unit price, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

Weak economic conditions and the volatility and disruption in the financial markets could increase the cost of raising money in the debt and equity capital markets substantially while diminishing the availability of funds from those markets. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. These factors may impair our ability to execute our growth strategy.

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing. Weak economic conditions and competition for asset purchases could limit our ability to fully execute our growth strategy.

We may not have access to capital due to deterioration of conditions in the global capital markets, weakening of macroeconomic conditions and negative changes in financial performance.

In general, we rely, in large part, on banks and capital markets to fund our operations, contractual commitments and refinance existing debt. These markets can experience high levels of volatility and access to capital can be constrained for an extended period of time. In addition to conditions in the capital markets, a number of other factors, including our financial performance and any sustained depression of natural gas, NGL and/or crude oil prices (including further extension of the low energy price environment that began in the second half of 2014), could cause us to incur increased borrowing costs and to have greater difficulty accessing public and private markets for both secured and unsecured debt. If we are unable to secure financing on acceptable terms, our other sources of funds, including available cash, bank facilities and cash flow from operations may not be adequate to fund our operations, contractual commitments and refinance existing debt.

Because 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 our 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.

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

As of December 31, 2014, we had total indebtedness of $475.6 million. 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 cash 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 effect any of these actions on satisfactory terms or at all.

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

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

Restrictions in our Credit Facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and the value of our common units.

We are dependent upon the earnings and cash flow generated by our operations in order to meet our debt service obligations and to make cash distributions to our unitholders. The operating and financial restrictions and covenants in our Credit Facility and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make cash distributions to our unitholders. Our Credit Facility limits our ability among other things, to:

- incur or guarantee additional debt;
- make distributions on or redeem or repurchase units;
- make certain investments and acquisitions;
- make capital expenditures;

- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

Our Credit Facility contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests. See Note 2 to our consolidated financial statements.

The provisions of our Credit Facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our Credit Facility could result in a default or an event of default that could enable our lenders, subject to the terms and conditions of our Credit Facility, 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.

For a complete description of long-term debt, see Note 8 to our consolidated financial statements.

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

Our natural gas gathering, processing, compression, treating and transportation operations and NGL fractionation services 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 (including, for example, the CAA, Comprehensive Environmental Response, Compensation, and Liability Act, the Endangered Species Act and the Resource Conservation and Recovery Act).

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 or at locations currently or previously owned or operated by us. Numerous governmental authorities, such as the EPA, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions or costly pollution control measures. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. In addition, we may experience a delay in obtaining or be unable to obtain required permits or regulatory authorizations, 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 and other 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 hazardous wastes and other materials 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. In addition, changes in environmental laws occur frequently, and any such changes that result in additional permitting obligations or 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.

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 considered legislation to restrict or regulate emissions of greenhouse gases, or GHGs, such as carbon dioxide and methane that may be contributing to global warming. It presently appears unlikely that comprehensive climate legislation will be passed by either house of U.S. 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). However, most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants.

Independent of the U.S. Congress, the EPA has adopted regulations controlling GHG emissions under its existing CAA authority. 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 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 GHGs under existing provisions of the CAA. For example, on September 22, 2009, the EPA issued a final rule requiring the monitoring and reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. 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 GHG emissions by regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. Our Gregory and Conroe processing facilities are currently required to report under this rule. However, operational or regulatory changes could require some or all of our other facilities to be required to report GHG emissions at a future date. For example, in December 2014, the EPA proposed additional amendments to its greenhouse gas reporting rule, which could add reporting requirements for additional facilities, including gathering and boosting systems. 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 GHG emissions under the CAA. On June 23, 2014, the U.S. Supreme Court ruled that the EPA exceeded its statutory authority when it interpreted the CAA to require PSD and Title V permitting for stationary sources based solely on their GHG emissions. However, the EPA still may require stationary sources to install best available control technologies to control GHG emissions if the stationary source is otherwise subject to the CAA's pre-construction and operating permitting programs for other pollutants. At this time, it is unclear how this ruling will affect our business; however, it appears to simplify permitting for sources that would have only triggered PSD for GHG emissions.

Although it is not possible at this time to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business, any future federal or state laws or implementing regulations that may be adopted to address GHG 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 GHGs could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any taxes related to our GHG emissions and administer and manage a GHG 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.

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

A portion of our customers' natural gas production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing has become the subject of opposition, additional private and government studies and increased federal, state and local regulation. For example, Congress may consider legislation to amend the Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act's Underground Injection Control Program and to require disclosure of chemicals used in the hydraulic fracturing process. The EPA has announced plans to develop standards for discharges of hydraulic fracturing wastewaters by 2015, has adopted new regulations under the CAA requiring, among other things, the use of "reduced emission completion" technology for certain hydraulic fracturing operations and related equipment, and has solicited public comment on a possible federal reporting requirement for fluids used in hydraulic fracturing pursuant to the Toxic Substances Control Act. Compliance with such laws and regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers, which may adversely impact our cash flows and results of operations.

Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. We cannot predict whether any other legislation will be enacted and if so, what its provisions would be. If additional levels of regulation and permits are required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and prohibitions for producers who drill near our pipelines which could reduce the volumes of natural gas available to move through our gathering systems which could materially and adversely affect our revenue and results of operations.

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 crude 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 or environmental authorizations. We may be unable to obtain such rights-of-way or authorizations 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 authorizations or to renew existing rights-of-way or authorizations. If the cost of renewing or obtaining new rights-of-way or authorizations increases materially, our cash flows could be adversely affected.

A change in the jurisdictional characterization or regulation of our assets or a change in regulatory laws and regulations or the implementation of existing laws and regulations 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 and gathering facilities 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 the FERC jurisdiction. We also 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 the FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and, over time, the FERC's policy for determining which facilities it regulates has changed. In addition, the distinction between the 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 the FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the Natural Gas Policy Act of 1978 ("NGPA"). 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 rate established by the FERC.

Some of our intrastate pipelines provide interstate transportation service regulated under Section 311 of the NGPA. Rates charged under Section 311 must be "fair and equitable," and amounts collected in excess of fair and equitable rates are subject to refund with interest. Accordingly, such regulation may prevent us from recovering our full cost of service allocable to such interstate transportation service. In addition, some of our intrastate pipelines may be subject to complaint-based state regulation with respect to our rates and terms and conditions of service, which may prevent us from recovering some of our costs of providing service. The inability to recover our full costs due to the FERC and state regulatory oversight and compliance could materially and adversely affect our revenues.

Moreover, the 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 transparency, market manipulation, ratemaking, capacity release, segmentation and market center promotion, directly and indirectly affect our gathering and pipeline transportation 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 safety and environmental regulation and complaint-based ratable take requirements and rate regulation. State and local regulation may cause us to incur additional costs or limit our operations, and may prevent us from choosing the customers to which we provide service. Due to increased gathering activity, among other considerations, natural gas gathering is beginning to receive greater legislative and regulatory scrutiny which could result in new regulations or enhanced enforcement of existing laws and regulations. Increased regulation of natural gas gathering could adversely affect our financial condition, results of operations, cash flows and our ability to make cash distributions to our unitholders.

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

The DOT, through its Pipeline and Hazardous Materials Safety Administration, 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" unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. High consequence areas include high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways. 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, including the states in which we operate, have adopted regulations similar to existing DOT regulations for intrastate pipelines. Although many of our pipeline facilities fall within a class that is currently 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 in South Texas. We have incurred costs of approximately $0.9 million during 2014 in order to complete the testing required by existing DOT regulations and their state counterparts. This expenditure included all costs associated with repairs, remediations, preventative and mitigating actions related to the 2014 testing program.

Should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. Additionally, pipeline safety reforms, including new requirements, enhanced penalties and changes in the administration and enforcement of safety laws have been implemented in recent years and the consideration of additional reforms is ongoing. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was enacted in 2010 and amended the Commodity Exchange Act. This law regulates derivative and commodity transactions, including crude oil and gas hedging transactions used in our risk management activities. The Dodd-Frank Act requires the Commodity Futures Trading Commission ("CFTC") and other regulators to promulgate rules and regulations implementing the new legislation. While many of the regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

In its rulemaking under the Dodd-Frank Act, the CFTC will likely finalize regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, although certain bona fide hedging transactions would be exempt from these position limits provided that various conditions are satisfied. Once finalized, the position limits rule and its companion rule on aggregation may have an impact on our ability to hedge our exposure to certain enumerated commodities.

The Dodd-Frank Act provisions are also 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 many swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. To date, several categories of interest rate and index credit default swaps have been designated by the CFTC as mandatorily clearable swaps. These swaps may also be required to be traded on registered swap execution facilities or exchanges. Both the clearing and the trading requirements are likely to significantly increase transaction costs of entering into swaps (e.g., by entering into agreements with and paying commission to brokerage and clearing intermediaries). Even if we chose to rely on the end-user exception from the clearing and trading requirements, we would be required to take certain steps to qualify for the end-user exception. As the CFTC further designates swap contracts as required to be cleared and traded on a trading facility, the utility of the end-user exception will become even more important. Our ability to rely on the end-user exception may change the profitability of our trades or the efficiency of our hedging.

The Dodd-Frank Act and any new regulations could, among other things, significantly increase the cost of entering into derivative and commodity contracts (including from swap recordkeeping and reporting requirements), materially alter the terms of derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, require greater collateral support for derivative contracts and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives 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. Any of these consequences could have a material adverse effect on our financial condition, results of operations and cash available for distribution.

Because the CFTC is still in the process of interpreting its regulations, it is possible that some of the derivative and commodity contracts used in our business may be treated differently in the future. For example, the CFTC may further revise its definitions for spots, forwards, forwards with volumetric optionality, trade options, full requirements contracts and certain other contracts that may combine the elements of physical commodity trades and cash settlement, netting and book-outs. If these contracts were classified as swaps, the costs of entering into these contracts will likely increase.

Finally, under the Dodd-Frank Act, the CFTC is also directed generally to prevent price manipulation and fraud in physical commodities markets traded in interstate commerce, including physical energy and other commodities, as well as financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation, anti-fraud and disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets. Accordingly, the CFTC and the self-regulatory organizations ("SROs"), such as commodity futures exchanges, are continuing to develop their respective enforcement authorities and compliance priorities under the Dodd-Frank Act. Given the novelty of the regulations under the Dodd-Frank Act, it is difficult to predict how these new enforcement priorities of the CFTC and the SROs will impact our business. Should we violate the Commodity Exchange Act, as amended, the regulations promulgated by the CFTC, and any rules adopted by the SROs thereunder, we could be subject to CFTC enforcement action and material penalties and sanctions.

Cyber-attacks, acts of terrorism or other disruptions could adversely impact our results of operations and our ability to make cash distributions to unitholders.

We are subject to cyber security risks related to breaches in the systems and technology that we use (i) to manage our operations and other business processes and (ii) to protect sensitive information maintained in the normal course of our businesses. The gathering, processing and transportation of natural gas from our gathering, processing and pipeline facilities are dependent on communications among our facilities and with third-party systems that may be delivering natural gas into or receiving natural gas and other products from our facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt our ability to deliver natural gas and control these assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt our operations and critical business functions, adversely affect our reputation and subject us to possible legal claims and liability, any of which could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. In addition, our natural gas pipeline systems may be targets of terrorist activities that could disrupt our ability to conduct our business and have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key management and personnel.

Our ability to operate our business and implement our strategies will depend on our continued ability to attract and retain highly skilled management personnel with midstream natural gas industry experience. Competition for these persons in the midstream natural gas industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. 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.

We do not have employees. We rely solely on officers and employees of our General Partner to operate and manage our business.

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 Exchange Act, including the rules thereunder that require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. 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 accounting principles generally accepted in the United States of America ("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, or Sarbanes-Oxley, which we refer to as Section 404.

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 are required to disclose changes made in our internal control and procedures on a quarterly basis and make an annual assessment of our internal control over financial reporting pursuant to Section 404. In addition, pursuant to the JOBS Act, our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal control over financial reporting until the date we are no longer an "emerging growth company," which may be through December 31, 2017.

The amount of cash we have available for distribution to holders of our common units, subordinated units and Class B Convertible 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

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

Holdings controls our General Partner and has the authority to appoint all of the officers and directors of our General Partner. Pursuant to the organizational documents of the general partner of Holdings, Tailwater has the right to designate two directors (one of whom must be independent), EIG has the right to designate two directors (one of whom must be independent), and Southcross Energy LLC has the right to designate two directors (one of whom must be independent). The seventh director and the chairman will be selected by a majority of the other directors. David W. Biegler has been designated as the chairman of the board of our General Partner until August 4, 2016 or until his earlier death or resignation. 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 also have a duty to manage our General Partner in a manner that is beneficial to its ultimate owner, Holdings. Conflicts of interest may arise between 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 Holdings over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our Third Amended and Restated Agreement of Limited Partnership ("Partnership Agreement") nor any other agreement requires Holdings to pursue a business strategy that favors us.
- Our General Partner is allowed to take into account the interests of parties other than us, such as Holdings, in resolving conflicts of interest.
- Our Partnership Agreement replaces the fiduciary duties that would otherwise be owed by our General Partner to us and our unitholders with contractual standards governing its duties to us and our unitholders, limits our General Partner's liabilities, and also restricts the rights of our unitholders with respect to 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, issuances 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 a growth 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 $35.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. 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 has limited 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.
- 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.

Each of Tailwater, EIG and Charlesbank is not limited in its ability to compete with us and is 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.

Tailwater, EIG and Charlesbank are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. Tailwater, EIG and Charlesbank may each 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 Tailwater, EIG and Charlesbank may offer us the opportunity to buy additional assets from them, none of them are under a contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed. Tailwater, EIG and Charlesbank are each private equity firms with significantly greater resources than us with experience making investments in midstream energy businesses. Tailwater, EIG and Charlesbank may each compete with us for investment opportunities and may own interests in entities that compete with us.

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

The market price of our common units may fluctuate significantly, and you could lose all or part of your investment.

There were 21,691,917 publicly traded common units as of December 31, 2014. In addition, Holdings owned 2,116,400 common units, 12,213,713 subordinated units and 14,889,078 Class B Convertible Units as of December 31, 2014. You may not be able to resell your common units at or above your acquisition price. Additionally, a lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The market price of our common units may decline and be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these "Risk Factors."

Our General Partner has limited its liability regarding our obligations.

Our General Partner has limited 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 expect that we will 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 growth 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 growth 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 or our Credit Facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

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

While our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our Partnership Agreement generally may not be amended during the subordination period without the approval of a majority our public common unitholders. However, our Partnership Agreement can be amended with the consent of our General Partner and the approval of a majority of the outstanding common units (including common units held by affiliates of our General Partner) after the subordination period has ended. As of December 31, 2014, Holdings, the 100% owner of our General Partner, owned, directly or indirectly, 8.9% of the outstanding common units, 100% of our outstanding subordinated units and 100% of our outstanding Class B Convertible Units.

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

We will reimburse our General Partner and its affiliates, including Holdings, for expenses they incur and payments they make on our behalf. Under our Partnership Agreement, we reimburse our General Partner and its affiliates for certain expenses incurred on our behalf including, among other items, compensation expense for all employees required to manage and operate our business. Our Partnership Agreement provides that our General Partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our General Partner and its affiliates reduce the amount of available cash to pay cash distributions to our common unitholders.

Our Partnership Agreement replaces our General Partner's fiduciary duties to holders of our common and subordinated units with contractual standards governing its duties.

Our Partnership Agreement contains provisions that eliminate the fiduciary duties to which our General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. 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, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the Partnership Agreement does not provide for a clear course of action. 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;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our General Partner;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights or any units it owns to a third party; 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 rights of holders of our common and subordinated units with respect to actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that restrict the rights of unitholders with respect to 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, meaning it subjectively believed that the decision was in the best interest of us and our unitholders, and except as specifically provided by our Partnership Agreement, will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as such decisions are made in good faith;
- 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 intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our General Partner will not be in breach of its obligations under the Partnership Agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
  - 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;
  - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates, although our General Partner is not obligated to seek such approval;
  - determined by the board of directors of our General Partner to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
  - determined by the board of directors of our General Partner to be 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 the final two subclauses 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 us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our Partnership Agreement provides that our conflicts committee may be comprised of one or more independent directors. If we establish a conflicts committee with only one independent director, your interests may not be as well served as if we had a conflicts committee comprised of at least two independent directors. A single-member conflicts committee would not have the benefit of discussion with, and input from, other independent directors.

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 our General Partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our General Partner in connection with resetting the target distribution levels related to our General Partner's incentive distribution rights.

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders 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 Holdings. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

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

Our unitholders are currently unable to remove our General Partner without its consent because our General Partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our General Partner. As of December 31, 2014, Holdings owns an approximate 57.4% limited partner interest in us. 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 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 us will most likely result in the termination of the subordination period and the 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 Holdings to transfer all or a portion of its 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. This effectively permits a "change of control" without the vote or consent of the unitholders.

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.

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

As of December 31, 2014, Holdings held an aggregate of 2,116,400 common units, 12,213,713 subordinated units and 14,889,078 Class B Convertible Units. All of the subordinated units will convert into common units at the end of the subordination period. The Class B Convertible Units will convert into common units when we make a distribution for any quarter to holders of common units equal to or more than $0.44 per common unit, we generated class B distributable cash flow, and paid, the declared distribution on all outstanding units for the two prior quarters, and we forecast paying a distribution equal to or more than $0.44 per outstanding unit from forecasted class B distributable cash flow on all outstanding units for the next two quarters. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

If at any time our General Partner and its affiliates own more than 80% of the common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our Partnership Agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of December 31, 2014, Holdings owned approximately 8.9% of our 23,800,943 outstanding common units. At the end of the subordination period and following the conversion of the Class B Convertible Units, assuming no additional issuances of common units (other than upon the conversion of the subordinated units and the Class B Convertible Units), Holdings will own approximately 57.4% 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 our general partner. We are 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 us 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 our interest nor liabilities that are non-recourse to us are counted for purposes of determining whether a distribution is permitted.

The TexStar Rich Gas System may not be as beneficial to us as we expect.

As a result of our acquisition of the TexStar Rich Gas System, we are subject to additional risks, in particular the risk we fail to realize the expected profitability, growth or accretion from the transaction. The acquisition of the TexStar Rich Gas System involves additional potential risks, including:

- failure to operate the current facilities and assets within operational expectations;

- construction cost overruns and delays resulting from numerous factors, many of which may be out of our control;
- the temporary diversion of management's attention from our existing business;
- an increase in our interest expense and financial leverage resulting from additional debt incurred to finance the TexStar Rich Gas System, which may offset the expected accretion from such acquisition;
- operations regarding the joint venture arrangements;
- the ability to add additional rich gas volumes onto our system;
- failure or delay of a project owned by a subsidiary of Holdings that is expected to bring additional gas volumes onto the TexStar Rich Gas System;
- title issues or liabilities or accidents;
- the incurrence of unanticipated liabilities and costs for which indemnification is unavailable or inadequate;
- environmental or regulatory compliance matters or liabilities.

If these risks or other unanticipated liabilities were to materialize, the desired benefits of the acquisition of the TexStar Rich Gas System may not be fully realized, and our future financial performance and results of operations could be negatively impacted.

We may be unable to grow through the acquisitions of current or future assets of Holdings, which could limit our ability to maintain or increase distributions to our unitholders.

Holdings is under no obligation to offer us the opportunity to purchase its current or future assets, and the board of directors of its general partner owes fiduciary duties to its members, and not our unitholders, in making any decision to offer us this opportunity. Likewise, we are not required to purchase any additional assets from Holdings.

The consummation of any such purchases will depend upon, among other things, our ability to reach an agreement with Holdings regarding the terms of such purchases (which will require the resolution of the conflict of interest pursuant to our Partnership Agreement) and our ability to finance such purchases on acceptable terms. Additionally, Holdings may be limited in its ability to consummate sales of additional portions of such business to us by the terms of its existing or future credit facilities. Furthermore, our credit facility includes covenants that may limit our ability to finance acquisitions. If a sale by Holdings of any additional assets would be restricted or prohibited by such covenants, we or Holdings may be required to seek waivers of such provisions or refinance those debt instruments in order to consummate a sale, neither of which may be accomplished timely, if at all. If we are unable to grow through additional acquisitions of Holdings's current or future assets, our ability to maintain or increase distributions to our unitholders may be limited.

Risks Related to our Common Units

The price of our common units may be adversely affected by the future issuance and sale of additional common units, including pursuant to the Distribution Agreement, or by our announcement that such issuances and sales may occur.

We cannot predict the size of future issuances or sales of our common units, including those made pursuant to the Distribution Agreement with any of our sales agents or in connection with future acquisitions or capital raising activities, or the effect, if any, that such issuances or sales may have on the market price of our common units. In addition, our sales agents will not engage in any transactions that stabilize the price of our common units. The issuance and sale of substantial amounts of common units, including issuances and sales pursuant to the Distribution Agreement, or announcement that such issuances and sales may occur, could adversely affect the market price of our common units.

Tax Risks

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

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

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

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. For example, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including the elimination of the qualifying income exception upon which we rely for our treatment as a partnership for federal income tax purposes. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to satisfy the requirements of the exception pursuant to which we are treated as a partnership for federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

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

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

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our 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. The IRS may adopt positions that differ from the positions we take or may take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all the positions we take or may take. A court may not agree with some or all of 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. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his or her return. Any audit of a unitholder's return could result in adjustments not related to our returns, as well as those related to our returns.

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

If our unitholders sell common units, they will recognize gain or loss for federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the common units they sell will, in effect, become taxable income to them if they sell such common units at a price greater than their tax basis in those common units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized on any sale of their 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 our unitholders sell their common units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investments in our 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, is unrelated business taxable income and is taxable to them. Distributions to non-U.S. persons are reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons are required to file federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult a tax advisor before investing in our common units.

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

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

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

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first business 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. The U.S. Department of the Treasury has issued proposed regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to 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 have adopted certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our General Partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

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

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

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

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

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

As a result of investing in our common units, our unitholders may be 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 are likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently conduct business in Alabama, Mississippi and Texas. Some of these states currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is our unitholders' responsibility to file all federal, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our real property falls into two categories:

1. parcels that we own in fee title; 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 remainder of the 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.

We are not aware 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. A description of our properties is included in Part I, Item 1 of this report and incorporated herein by reference.

Item 3. Legal Proceedings

From time to time, we are party to certain legal or administrative proceedings that arise in the ordinary course and are incidental to our business. For example, during periods when we are expanding our operations through the development of new pipelines or the construction of new plants, we may become involved in disputes with landowners that are in close proximity to our activities. While we are currently involved in several such proceedings and disputes, our management believes that none of such proceedings or disputes will have a material adverse effect on our results of operations, cash flows or financial condition. However, future events or circumstances, currently unknown to management, will determine whether the resolution of any litigation or claims ultimately will have a material effect on our results of operations, cash flows or financial condition in any future reporting periods.

On March 5, 2013, one of our subsidiaries, Southcross Marketing Company Ltd., filed suit in a District Court of Dallas County against Formosa Hydrocarbons Company, Inc. ("Formosa"). The lawsuit sought recoveries of losses that we believe our subsidiary experienced as a result of the failure of Formosa to perform certain obligations under the gas processing and sales contract between the parties. Formosa filed a response generally denying our claims and, later, Formosa filed a counterclaim against our subsidiary claiming our affiliate breached the gas processing and sales contract and a related agreement between the parties for the supply by Formosa of residue gas to a third party on behalf of our subsidiary. After a bench trial held in January 2015, on February 5, 2015, the judge ruled that Formosa breached certain of its obligations under the gas processing and sales contract and that our subsidiary breached an obligation under each of the gas processing and sales contract and the related residue gas agreement. The amount of damages awarded to our subsidiary was in excess of the damages awarded to Formosa. However, the ultimate amount to be recovered by our subsidiary will not be finalized until the judge awards attorneys' fees, if any. Until that issue is resolved, a judgment will not be entered and, as a result, we do not know the ultimate financial outcome of the lawsuit. Regardless of the attorneys' fee issue, the judgment is not expected to have a material impact on our results of operations, cash flows or financial condition. We currently expect a final judgment to be entered in the second quarter of 2015, which may be appealed.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities

Market Information

Our common units have been listed on the NYSE since November 2, 2012 under the symbol "SXE." The table below sets forth the high and low sales prices of our common units and the per unit distributions declared since January 1, 2013. Distributions are recorded when paid.

	Unit Prices		Distributions		
	High	Low	per common unit	Record date	Payment date
Quarter Ended December 31, 2014	$22.17	$11.22	$0.40	February 9, 2015	February 13, 2015
Quarter Ended September 30, 2014	24.88	21.11	0.40	November 5, 2014	November 14, 2014
Quarter Ended June 30, 2014	23.50	16.51	0.40	August 8, 2014	August 15, 2014
Quarter Ended March 31, 2014	19.29	14.92	0.40	May 9, 2014	May 15, 2014
Quarter Ended December 31, 2013	21.00	16.21	0.40	February 5, 2014	February 14, 2014
Quarter Ended September 30, 2013	24.78	16.73	0.40	November 7, 2013	November 14, 2013
Quarter Ended June 30, 2013	23.67	18.34	0.40	August 9, 2013	August 14, 2013
Quarter Ended March 31, 2013	26.49	20.15	0.40	May 10, 2013	May 15, 2013

The last reported sale price of our common units on the NYSE on March 2, 2015 was $12.76 and, as of such date, there were approximately 5,685 holders of record of our common units and 21,684,543 common units outstanding. As of March 2, 2015, we have issued 12,213,713 subordinated units, 15,149,636 Class B Convertible Units and 1,044,170 general partner units, for which there is no established trading market.

Distribution of Available Cash

General. Our Partnership Agreement requires that within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our General Partner.

Definition of Available Cash. Available cash generally means, for any quarter, all cash on hand at the end of that quarter:

- less the amount of cash reserves established by our General Partner at the date of determination of available cash for that quarter to:
    - provide for the proper conduct of our business (including reserves for our future capital expenditures and anticipated future credit needs);
    - comply with applicable law, any of our debt instruments or other agreements; or
    - provide funds for distributions to our unitholders and to our General Partner for any one or more of the next four quarters (provided that our General Partner may not establish cash reserves for distributions unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);
- plus, if our General Partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Working capital borrowings are generally borrowings that are made under a credit facility or another arrangement that are used solely for working capital purposes or to pay distributions to unitholders, and are intended to be repaid within 12 months.

Minimum Quarterly Distribution. Commencing with the fourth quarter of 2012, we made quarterly distributions to the holders of our common units and, until the third quarter of 2014, to the holders of our subordinated units of $0.40 per unit, or $1.60 on an annualized basis (with the first such distribution being prorated). We intend to continue to make a minimum quarterly distribution to unitholders to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our General Partner. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our General Partner, taking into consideration the terms of our Partnership Agreement and requirements under our Credit Facility (as defined below). Beginning with the third quarter of 2014, until such time that we have a ratio of distributable cash flow divided by cash distributions ("Distributable Cash Flow Ratio") of at least 1.0, Holdings, the holder of all of our subordinated units, has waived the right to receive distributions on any subordinated units that would cause the Distributable Cash Flow Ratio to be less than 1.0. With respect to the fourth quarter of 2014, Holdings waived the requirement that any distribution owed to it for that quarter be paid within 45 days of the end of the quarter, provided that the distribution is paid before or in conjunction with the filing of this Form 10-K.

General Partner Interest and Incentive Distribution Rights

Our General Partner is currently entitled to 2.0% of all distributions that we make prior to our liquidation. Our General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current General Partner interest. Our General Partner's initial 2.0% interest in our distributions will be reduced if we issue additional limited partner units in the future and our General Partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

Our General Partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus in excess of $0.46 per unit per quarter. The maximum distribution of 50% includes distributions paid to our General Partner on its 2.0% general partner interest and assumes that our General Partner maintains its general partner interest at 2.0%. The maximum distribution of 50% does not include any distributions that our General Partner may receive on any limited partner units that it owns.

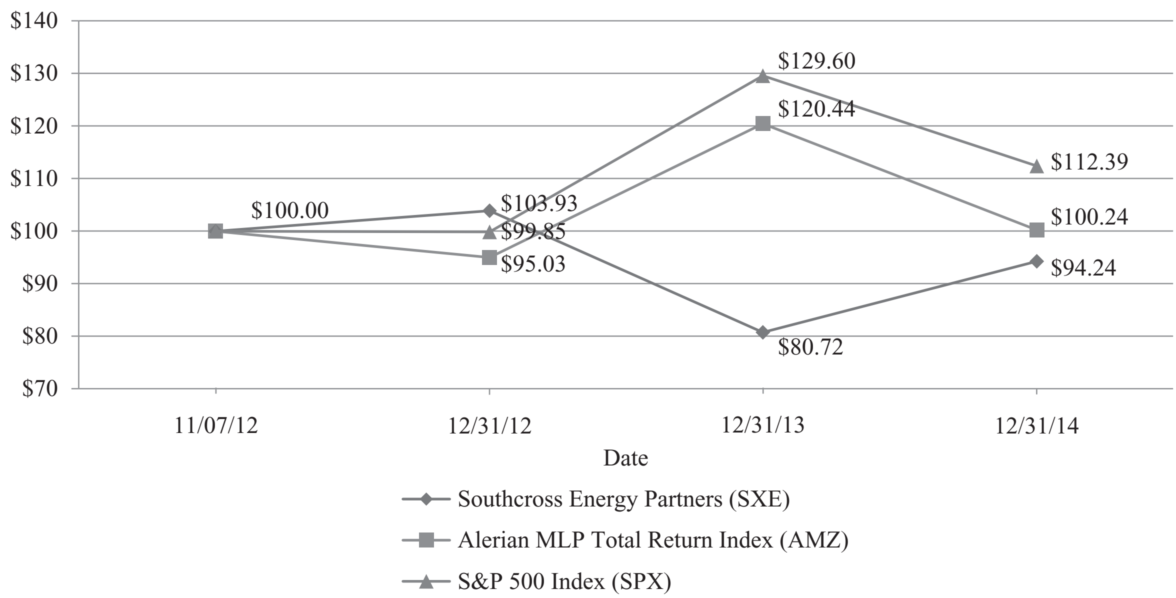
The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our General Partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our General Partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit Target Amount." The percentage interests shown for our unitholders and our General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our General Partner include its 2.0% general partner interest and assume that our General Partner has contributed any additional capital necessary to maintain its 2.0% general partner interest, our General Partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest In Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.40	98%	2%
First target distribution	$0.40 up to $0.46	98%	2%
Second target distribution	above $0.46 up to $0.50	85%	15%
Third target distribution	above $0.50 up to $0.60	75%	25%
Thereafter	above $0.60	50%	50%

Performance Graph

The following performance graph compares the cumulative total unitholder return of our common units with the Standard & Poor's 500 Stock Index ("S&P 500") and the Alerian MLP Total Return Index for the period from our IPO (November 7, 2012) to December 31, 2014, assuming an initial investment of $100.

Comparison of Cumulative Total Return



Securities Authorized for Issuance Under Equity Compensation Plan

See discussion in Part III, Item 12 of this report entitled "Securities Authorized for Issuance Under Equity Compensation Plan."

Item 6. Selected Financial Data

The information in this section should be read in conjunction with Part II, Item 7 and Item 8 of this report. The preparation of our consolidated financial statements requires us to make a number of significant judgments and estimates, as well as consider a number of uncertainties (in thousands, except per unit data and volume data).

	Year Ended December 31,				
	2014[(1)]	2013[(1)]	2012[(1)]	2011[(1)]	2010[(1)]
Statements of operations data:					
Revenues	$ 842,727	$ 634,722	$ 496,129	$ 523,149	$ 498,747
(Loss) income from operations	(6,819)	(3,020)	3,289	16,388	19,733
Net loss	(31,322)	(15,970)	(4,488)	—	—
Series A Preferred fair value adjustment	(4,596)	(1,670)	—	—	—
Net loss from January 1, 2012 through November 6, 2012	—	—	(260)	—	—
Net loss attributable to partners	(36,659)	(17,640)	(4,228)	—	—
General partner's interest	(693)	(319)	(85)	—	—
Limited partners' interest	(35,966)	(17,321)	(4,143)	—	—
Net (loss) income from Southcross Energy LLC			(260)	7,539	9,719
Less deemed dividend on:					
Redeemable preferred units			(2,693)	(1,553)	—
Series B redeemable preferred units			(4,696)	—	—
Series C redeemable preferred units			(2,012)	—	—
Preferred units			(13,249)	(14,131)	(12,802)
Net loss attributable to Southcross Energy LLC common unitholders			(22,910)	(8,145)	(3,083)
Basic and diluted earnings per unit					
Net loss allocated to limited partner common units (from November 7, 2012)	(20,175)	(8,683)	(2,072)	—	—
Weighted average number of limited partner common units outstanding	21,641,635	12,224,997	12,213,713	—	—
Loss per common unit	(0.93)	(0.71)	(0.17)	—	—
Net loss allocated to Southcross Energy LLC common units	—	—	(22,910)	(8,145)	(3,083)
Weighted average number of Southcross Energy LLC common units outstanding	—	—	1,198,429	1,197,876	1,197,257
Loss per Southcross Energy LLC common unit[(2)]	—	—	(19.12)	(6.79)	(2.57)
Performance measures:					
Distributions declared per common unit[(3)]	1.60	1.60	0.24	n/a	n/a
Other financial data:					
Adjusted EBITDA[(4)]	54,503	34,486	24,019	28,957	30,869
Gross operating margin[(4)]	121,595	93,546	71,640	62,569	59,316
Maintenance capital expenditures	5,777	3,353	5,193	5,317	3,402
Growth capital expenditures	114,982	90,510	164,623	150,669	1,843
Operating data:					
Average throughput volumes of natural gas (MMBtu/d)[(5)]	884,259	622,238	570,599	506,975	471,265
Average volume of processed gas (MMBtu/d)	353,456	240,825	206,045	155,475	153,557
Average volume of NGLs fractionated (Bbls/d)	17,815	12,545	9,385	5,131	5,557
Realized prices on natural gas volumes sold/Btu ($/MMBtu)	4.40	3.75	2.83	4.05	4.42
Realized prices on NGL volumes sold/gal ($/gal)	0.78	0.88	0.87	1.35	1.10
Balance sheet data (at period end):					
Cash and cash equivalents	1,649	3,349	7,490	1,412	20,323
Trade accounts receivable	71,159	57,669	50,994	41,234	35,059
Property, plant, and equipment, net	968,810	575,795	550,603	369,861	229,309
Total assets	1,223,627	652,315	618,605	420,385	289,643
Total debt (current and long term)	475,629	267,300	191,000	208,280	115,000
Capital leases	1,033	908	—	—	—
Series A convertible preferred unit in-kind distribution and fair value adjustment	—	40,504	—	—	—

(1) Reflects financial data of Southcross Energy Partners, L.P. subsequent to our IPO on November 7, 2012, and Southcross Energy LLC for periods ending prior to November 7, 2012.

(2) Earnings per unit of Southcross Energy LLC prior to our IPO.

(3) A distribution of $0.24 attributable to fourth quarter 2012 is the first distribution declared by us and corresponds to the minimum quarterly distribution of $0.40 per unit, or $1.60 on an annualized basis, pro-rated for the portion of the quarter following the closing of our IPO on November 7, 2012.

(4) See Part II, Item 7 of this report for definition of Non-GAAP financial metrics and reconciliation of such metrics to their most directly comparable GAAP financial measure.

(5) Average throughput volumes of natural gas per day include sales, transportation, fuel and shrink volumes for all periods presented. Historical average throughput volumes of natural gas per day presented previously included sales and transportation volume only.

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

The following is a discussion of our historical consolidated financial condition and results of operations that is intended to help the reader understand our business, results of operations and financial condition. It should be read in conjunction with other sections of this report, including our historical consolidated financial statements and accompanying notes thereto included in Part II, Item 8 of this report.

Overview and How We Evaluate our Operations

Overview

Southcross Energy Partners, L.P. (the "Partnership," "Southcross," "we," "our" or "us") is a Delaware limited partnership formed in April 2012. Southcross Energy LLC is a Delaware limited liability company, and the predecessor for accounting purposes (the "Predecessor") of the Partnership. References in this Form 10-K to the Partnership, when used for periods prior to our initial public offering ("IPO") on November 7, 2012, refer to Southcross Energy LLC and its consolidated subsidiaries, unless otherwise specifically noted. References in this Form 10-K to the Partnership, when used for periods beginning at or following our IPO, refer collectively to the Partnership and its consolidated subsidiaries. Until August 4, 2014, Southcross Energy LLC held all of the equity interests in Southcross Energy Partners GP, LLC, a Delaware limited liability company and our general partner ("General Partner"), all of our subordinated units, as well as a portion of our common units and Series A Convertible Preferred Units ("Series A Preferred Units"). Southcross Energy LLC is controlled through investment funds and entities associated with Charlesbank Capital Partners, LLC ("Charlesbank").

On August 4, 2014, Southcross Energy LLC and TexStar Midstream Services, LP ("TexStar") combined pursuant to a contribution agreement in which Southcross Holdings LP, a Delaware limited partnership ("Holdings"), was formed (the "Holdings Transaction"). As a result of the Holdings Transaction, Holdings owns 100% of our General Partner (and therefore controls us), all of our subordinated units and a portion of our common units. Charlesbank, EIG Global Energy Partners, LLC ("EIG") and Tailwater Capital LLC ("Tailwater") (collectively, the "Sponsors") each indirectly own approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine Opportunities Fund and GE Energy Financial Services own certain additional ownership interests in Holdings as well.

We are a master limited partnership that provides natural gas gathering, processing, treating, compression and transportation services and NGL fractionation and transportation services. We also source, purchase, transport and sell natural gas and NGLs. Our assets are located in South Texas, Mississippi and Alabama and include four gas processing plants, two fractionation facilities and approximately 3,005 miles of pipeline. We are headquartered in Dallas, Texas.

See Note 2 to our consolidated financial statements for a discussion of our liquidity.

General Trends and Outlook

Our business environment and corresponding operating results are affected by 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. Key trends that we monitor while managing our business include natural gas supply and demand dynamics overall and in our markets as well as growth production from U.S. shale plays, with specific attention on the Eagle Ford Shale region.

Natural Gas and NGL Environment

According to the U.S. Energy Information Administration (the "EIA") natural gas production in the United States reached its highest recorded annual total in 2014 and is expected to increase from over 74 billion cubic feet per day ("Bcf/d") on average in 2014 to over 78 Bcf/d on average in 2016, with almost all of the growth coming from shale formations. In 2007, shale gas wells made up approximately 9% of total natural gas produced in the U.S. By the end of 2014, shale gas wells accounted for nearly half of U.S. natural gas production. Natural gas production from shale formations in seven U.S. regions including the Eagle Ford, Permian, Haynesville, Niobrara, Bakken, Utica and Marcellus regions, accounted for 100% of domestic natural gas production growth from 2011 to 2013. The continued growth in shale gas production is expected to result from the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale and other plays with high concentrations of NGLs and crude oil, which in energy-equivalent terms, have a higher value than dry natural gas.

The EIA projects that U.S. natural gas consumption will increase to an average of 73.8 Bcf/d in 2015 and 74.8 Bc/d in 2016, compared with an estimated 73.6 Bcf/d in 2014. The growth in consumption is expected to be driven largely by the industrial and electric power sectors. Major consumers of natural gas in the United States in 2014 included the electric power generation sector with consumption of 22.7 Bcf/d, the industrial sector with 25.3 Bcf/d, the residential sector with 12.5 Bcf/d and 8.7 Bcf/d from the commercial sector. Growing domestic natural gas production is expected to reduce demand for imports from Canada and spur exports to Mexico. EIA expects exports to Mexico, particularly from the Eagle Ford Shale in South Texas, to increase because of growing demand from Mexico's electric power sector coupled with flat Mexican natural gas production.

In certain regions where the economics of natural gas production are less favorable, some natural gas producers have cut back or suspended their drilling operations as a result of the current low natural gas price environment. Drilling activities focused in liquids-rich regions have continued at better rates than dry gas regions as the high Btu content associated with liquids-rich production enhances overall drilling economics, even in a low natural gas price environment.

Average daily gas production in the Eagle Ford Shale in South Texas reached 6.6 Bcf/d on average in 2014, 25% higher than in 2013. The Eagle Ford Shale accounted for approximately 7.3 Bcf/d of U.S. natural gas production in December 2014, an increase of approximately 1.7 Bcf/d from December 2013. According to the EIA, average rig count in the Eagle Ford Shale region in 2014 increased by 2 rigs or approximately 1% to 288 rigs while the average gas production per rig increased by approximately 10% to approximately 1.4 MMcf/d. The outpaced growth in natural gas production relative to the increase in rig count primarily reflects increased drilling productivity including enhanced drilling and recovery techniques. EIA expects that increases in drilling efficiency and growth in oil production will continue to support growing natural gas production in the coming years.

The current depressed natural gas, NGL and crude oil price environment could negatively affect the level of natural gas, NGL and crude oil production which in turn could negatively impact the volume of natural gas flowing on our system.

We expect that the continued long term environment for natural gas demand will be favorable, driven by population, economic growth and the export market, as well as the continued replacement of coal electricity generation by natural gas electricity generation due to the low prices of natural gas and stricter governmental and environmental regulations on the mining and burning of coal.

According to EIA forecasts, the United States will become a net exporter of liquid natural gas ("LNG") in 2016. U.S. exports of LNG from new liquefaction capacity are expected to average 0.8 Bcf/d in 2016.

Interest rate environment

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. This could affect our ability to access the debt capital markets to the extent we may need to in the future to fund our growth. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. The current depressed natural gas, NGL and crude oil price environment could also negatively affect our ability to access the debt capital markets.

Although these risk factors could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as we believe our competitors would likely face similar circumstances.

Our Operations

Our integrated operations provide a full range of complementary services extending from wellhead to market, including gathering natural gas at the wellhead, treating natural gas to meet downstream pipeline and customer quality standards, processing natural gas to separate NGLs from natural gas, fractionating NGLs into the various components and selling or delivering pipeline quality natural gas, y-grade and purity product NGLs to various industrial and energy markets as well as large pipeline systems. Through our network of pipelines, we connect supplies of natural gas to our customers, which include industrial, commercial and power generation customers and local distribution companies. All of our operations are managed as and presented in one reportable segment.

Our results are determined primarily by the volumes of natural gas we gather and process, the efficiency of our processing plants and NGL fractionation plants, the commercial terms of our contractual arrangements, natural gas and NGL prices and our operations and maintenance expense. We manage our business with the goal to maximize the gross operating margin we earn from contracts balanced against any risks we assume in our contracts. Our contracts vary in duration from one month to several years and the pricing under our contracts varies depending upon several factors, including our competitive position, our acceptance of risks associated with longer-term contracts and our desire to recoup over the term of the contract any capital expenditures that we are required to incur to provide service to our customers. We purchase, gather, process, treat, compress, transport and sell natural gas and purchase, fractionate, transport and sell NGLs. Contracts with a counterparty generally contain one or more of the following arrangements:

- ***Fixed-Fee.*** We receive a fixed-fee per unit of natural gas volume that we gather at the wellhead, process, treat, compress and/or transport for our customers, or we receive a fixed-fee per unit of NGL volume that we fractionate. Some of our arrangements also provide for a fixed-fee for guaranteed transportation capacity on our systems.
- ***Fixed-Spread.*** Under these arrangements, we purchase natural gas and NGLs from producers or suppliers at receipt points on our systems at an index price plus or minus a fixed price differential and sell these volumes of natural gas and NGLs at delivery points off our systems at the same index price, plus or minus a fixed price differential. By entering into such back-to-back purchases and sales, we are able to mitigate our risk associated with changes in the general commodity price levels of natural gas and NGLs. We remain subject to variations in our fixed-spreads to the extent we are unable to precisely match volumes purchased and sold in a given time period or are unable to secure the supply or to produce or market the necessary volume of products at our anticipated differentials to the index price.
- ***Commodity-Sensitive.*** In exchange for our processing services, we may remit to a customer a percentage of the proceeds from our sales, or a percentage of the physical volume, residue natural gas and/or NGLs that result from our natural gas processing, or we may purchase NGLs from customers at set fixed NGL recoveries and retain the balance of the proceeds or physical commodity for our own account. These arrangements are generally combined with fixed-fee and fixed-spread arrangements for processing services and, therefore, represent only a portion of a contract’s value. The revenues we receive from these arrangements directly correlate with fluctuating general commodity price levels of natural gas and NGLs and the volume of NGLs recovered relative to the fixed recovery obligations.

We assess gross operating margin opportunities across our integrated value stream so that processing margins may be supplemented by gathering and transportation fees and opportunities to sell residue gas and NGLs at fixed-spreads. Gross operating margin earned under fixed-fee and fixed-spread arrangements is directly related to the volume of natural gas that flows through our systems and is generally independent from general commodity price levels. A sustained decline in commodity prices could result in a decline in volumes entering our system and, thus, a decrease in gross operating margin for our fixed-fee and fixed-spread arrangements.

The following table summarizes our gross operating margins from these arrangements (in thousands):

	Year Ended December 31,					
	2014		2013		2012	
	Gross Operating Margin	%	Gross Operating Margin	%	Gross Operating Margin	%
Fixed-fee	$ 84,972	69.9%	$59,532	63.7%	$48,055	67.0%
Fixed-spread	9,009	7.4%	11,143	11.9%	18,737	26.2%
Sub-total	93,981	77.3%	70,675	75.6%	66,792	93.2%
Commodity-sensitive	27,614	22.7%	22,871	24.4%	4,848	6.8%
Total gross operating margin	$121,595	100.0%	$93,546	100.0%	$71,640	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 quarterly basis for consistency and trend analysis. These performance metrics include (a) volume, (b) gross operating margin, (c) operations and maintenance expense, (d) Adjusted EBITDA and (e) distributable cash flow.

Volume—We determine and analyze volumes by operating unit, but report overall volumes after elimination of intercompany deliveries. The volume of natural gas and NGLs on our systems depends on the level of production from natural gas wells connected to our systems and also from wells connected with other pipeline systems that are interconnected with our systems.

Gross Operating Margin — Gross operating margin of our contracts is one of the metrics we use to measure and evaluate our performance. Gross operating margin is not a measure calculated in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We define gross operating margin as the sum of revenues less the cost of natural gas and NGLs sold. For our fixed-fee contracts, we record the fee as revenue and there is no offsetting cost of natural gas and NGLs sold. For our fixed-spread and commodity-sensitive arrangements, we record as revenue all of our proceeds from the sale of the natural gas and NGLs and record as an expense the associated cost of natural gas and NGLs sold.

Operations and Maintenance Expense—Our management seeks to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating and maintaining our assets. Direct labor costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities and contract services comprise the most significant portion of our operations and maintenance expense. These expenses are relatively stable and largely independent of volumes delivered through our systems, but may fluctuate depending on the activities performed during a specific period.

Adjusted EBITDA and Distributable Cash Flow—We believe that Adjusted EBITDA and distributable cash flow are widely accepted financial indicators of our operational performance and our ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA and distributable cash flow are not measures calculated in accordance with GAAP.

We define Adjusted EBITDA as net income/loss, plus interest expense, income tax expense, depreciation and amortization expense, equity in losses of joint venture investments, certain non-cash charges (such as non-cash unit-based compensation, impairments, loss on extinguishment of debt and unrealized losses on derivative contracts), major litigation costs net of recoveries, transaction-related costs, revenue deferral adjustment, loss on sale of assets and selected charges that are unusual or non-recurring; less interest income, income tax benefit, unrealized gains on derivative contracts, equity in earnings of joint venture investments and selected gains that are unusual or non-recurring. Adjusted EBITDA should not be considered an alternative to net income, operating cash flow or any other measure of financial performance presented in accordance with GAAP.

Adjusted EBITDA is used as a supplemental measure 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 future cash distributions;
- 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 investment opportunities.

We define distributable cash flow as Adjusted EBITDA, plus interest income and income tax benefit, less cash paid for interest (net of capitalized costs), income tax expense and maintenance capital expenditures. We use distributable cash flow to analyze our performance and liquidity. Distributable cash flow does not reflect changes in working capital balances.

Distributable cash flow is used to assess:

- the ability of our assets to generate cash sufficient to support our indebtedness and make future cash distributions to our unitholders; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

Non-GAAP Financial Measures

Gross operating margin, Adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We believe that the presentation of these non-GAAP financial measures provides useful information to investors in assessing our financial condition, results of operations and cash flows from operations. Net income is the GAAP measure most directly comparable to each of gross operating margin and Adjusted EBITDA. The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Each of these non-GAAP financial measures has important limitations as an analytical tool because each excludes some but not all items that affect the most directly comparable GAAP financial measure. You should not consider any of gross operating margin, Adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross operating 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.

Reconciliations of Non-GAAP Financial Measures

The following table presents a reconciliation of gross operating margin to net (loss) income (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Reconciliation of gross operating margin to net loss			
Gross operating margin	$121,595	$ 93,546	$ 71,640
Add (deduct):			
Income tax expense	(52)	(385)	(246)
Equity in losses of joint venture investments	(6,496)	—	—
Interest expense	(15,562)	(12,590)	(5,767)
Loss on extinguishment of debt	(2,316)	—	(1,764)
Other expense	(77)	—	—
Loss (gain) on sale of assets	(365)	25	—
General and administrative	(32,385)	(21,764)	(13,842)
Impairment of assets	(1,556)	—	—
Depreciation and amortization	(42,206)	(33,548)	(18,977)
Operations and maintenance	(51,902)	(41,254)	(35,532)
Net loss	$ (31,322)	$(15,970)	$ (4,488)

The following table presents a reconciliation of net cash flows provided by operating activities to net loss, Adjusted EBITDA, and distributable cash flow (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Net cash provided by operating activities	$ 48,335	$ 15,973	$ 24,323
Add (deduct):			
Depreciation and amortization	(42,206)	(33,548)	(18,977)
Unit-based compensation	(10,074)	(2,186)	(630)
Loss on extinguishment of debt	(2,316)	—	(1,764)
Amortization of deferred financing costs	(2,005)	(1,287)	(1,183)
Loss (gain) on sale of assets, net	(365)	25	—
Unrealized gain (loss) on financial instruments	(168)	120	(141)
Equity in losses of joint venture investments	(6,496)	—	—
Impairment of assets	(1,556)	—	—
Other, net	(65)	(130)	—
Changes in operating assets and liabilities:			
Trade accounts receivable, including affiliates	22,695	6,675	9,760
Prepaid expenses and other current assets	5	1,197	1,246
Other non-current assets	29	(215)	(1,786)
Accounts payable and accrued expenses	(34,480)	(1,411)	(16,517)
Other liabilities, including affiliates	(2,655)	(1,183)	1,181
Net loss	**$(31,322)**	**$(15,970)**	**$ (4,488)**
Add (deduct):			
Depreciation and amortization	42,206	33,548	18,977
Interest expense	15,562	12,590	5,767
Unrealized (gain) loss on commodity swaps	8	(120)	141
Loss on extinguishment of debt	2,316	—	1,764
Revenue deferral adjustment	2,514	—	—
Unit-based compensation	2,931	2,186	630
Income tax expense	52	385	246
Loss (gain) on sale of assets, net	365	(25)	—
Major litigation costs, net of recoveries	1,904	517	—
Equity in losses of joint venture investments	6,496	—	—
Transaction-related costs	9,850	—	—
Impairment of assets	1,556	—	—
Other, net	65	1,375	982
Adjusted EBITDA	**$ 54,503**	**$ 34,486**	**$ 24,019**
(Deduct):			
Cash interest, net of capitalized costs	(13,371)	(11,187)	(4,584)
Income tax expense	(52)	(385)	(246)
Maintenance capital expenditures	(5,777)	(3,353)	(5,193)
Distributable cash flow	**$ 35,303**	**$ 19,561**	**$ 13,996**

Current Year Highlights

The following events that took place during 2014 impacted or are likely to impact our financial condition and results of operations. The following should be read in conjunction with Part I, Item 1 of this report for a more detailed account of such events.

Financing Activities

Public Equity Offering

In February 2014, we completed a public equity offering of 9,200,000 additional common units and received a capital contribution from our General Partner to maintain its 2.0% interest in us. The net proceeds from the public offering of common units were $144.7 million. The net proceeds from the offering were used to fund the construction of our new pipeline extending into Webb County, Texas (the "Webb Pipeline"), our Onyx pipelines acquisition in March 2014 and for general partnership purposes.

Onyx Pipelines Acquisition

On March 6, 2014, our subsidiary, Southcross Nueces Pipelines LLC, acquired natural gas pipelines near Corpus Christi, Texas and contracts related to these pipelines from Onyx Midstream, LP and Onyx Pipeline Company (collectively, "Onyx") for $38.6 million in cash, net of certain adjustments as provided in the purchase agreement. See Note 3 to our consolidated financial statements.

TexStar Rich Gas System Acquisition

On August 4, 2014, we acquired from TexStar certain gathering and processing assets (the "TexStar Rich Gas System") for $80 million in cash, the assumption of $100 million of debt (which was immediately repaid through our Term Loan Agreement (as defined below)) and our issuance of 14,633,000 of our Class B Convertible Units to TexStar (See Note 3 to our consolidated financial statements). The TexStar Rich Gas System consists of a 300 MMcf/d cryogenic processing plant, located in Bee County, Texas, and joint venture ownership in over 230 miles of rich natural gas gathering and residue pipelines across the core producing areas extending from Dimmit to Karnes Counties, Texas in the liquids-rich window of the Eagle Ford Shale. These pipelines are operated under split-capacity arrangements within joint ventures with Atlas Pipeline Partners, L.P. See Notes 1 and 3 to our consolidated financial statements.

Senior Credit Facilities

On August 4, 2014, in connection with the consummation of the Holdings Transaction, we entered into (a) a Third Amended and Restated Revolving Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, JPMorgan Chase Bank, N.A., as Documentation Agent, and a syndicate of lenders (the "Third A&R Revolving Credit Agreement") and (b) a Term Loan Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, and a syndicate of lenders (the "Term Loan Agreement" and, together with the Third A&R Revolving Credit Agreement, the "Senior Credit Facilities"). See Note 8 to our consolidated financial statements.

Equity Distribution Agreement

On November 12, 2014, we established a $75 million "at-the-market" equity offering program pursuant to an equity distribution agreement (the "Distribution Agreement") with Wells Fargo Securities, LLC, J.P. Morgan Securities LLC and RBC Capital Markets, LLC (each, a "Manager" and, collectively, the "Managers"). Under the Distribution Agreement, we may offer and sell up to $75 million in aggregate gross sales proceeds of our common units (the "Offered Units") from time to time through the Managers, each as our sales agent. Sales of the Offered Units, if any, made under the Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices prevailing at the time of sale in block transactions, or as otherwise agreed upon by us and any Manager. For additional details regarding the Distribution Agreement, see Note 12 to our consolidated financial statements.

Webb Pipeline Construction

During the first quarter of 2014, we began construction of an addition to our pipeline systems into Webb County, Texas (the “Webb Pipeline”), which was completed in October 2014. During 2014, we incurred $70.8 million related to the Webb Pipeline which we limited to approximately 45 miles in the third quarter of 2014 as a result of our ability to use a part of the TexStar Rich Gas System assets to connect the Webb Pipeline to the rest of our system.

Key Factors Affecting Operating Results and Financial Condition

- ***Acquisition of rich gas assets from TexStar.*** In August 2014, we acquired the Lone Star plant, a 300 MMcf/d natural gas processing facility along with joint venture entities that own 176 miles of natural gas gathering and 57 miles of residue pipelines across core producing areas of the liquids-rich window of the Eagle Ford Shale.
- ***New pipelines in operation.*** In October 2014, we completed construction and commenced operation of our Webb County pipeline extension. The Webb Pipeline is a 45 mile 24 inch pipeline which connects Eagle Ford Shale region supply to our joint venture pipelines in LaSalle County for further delivery to our processing plants.
- ***Acquisition of Onyx pipelines and contracts.*** In March 2014, our subsidiary, Southcross Nueces Pipelines LLC, acquired natural gas pipelines in Nueces and San Patricio Counties, Texas and contracts related to these pipelines from Onyx. These pipelines transport natural gas to two power plants in Nueces County, Texas under fixed-fee contracts that extend through 2029 and include an option to extend the agreements by an additional term of up to ten years.

Results of Operations

The following table summarizes our results of operations (in thousands, except operating data):

	Year Ended December 31,		
	2014	2013	2012
Revenues			
Revenues	$829,460	$634,722	$496,129
Revenues—affiliates	13,267	—	—
Total revenues	842,727	634,722	496,129
Expenses:			
Cost of natural gas and liquids sold	721,132	541,176	424,489
Operations and maintenance	51,902	41,254	35,532
Depreciation and amortization	42,206	33,548	18,977
General and administrative	32,385	21,764	13,842
Impairment of assets	1,556	—	—
Loss (gain) on sale of assets	365	(25)	—
Total expenses	849,546	637,717	492,840
(Loss) income from operations	(6,819)	(2,995)	3,289
Other income (expense):			
Equity in losses of joint venture investments	(6,496)	—	—
Interest expense	(15,562)	(12,590)	(5,767)
Loss on extinguishment of debt	(2,316)	—	(1,764)
Other expense	(77)	—	—
Total other expense	(24,451)	(12,590)	(7,531)
Loss before income tax expense	(31,270)	(15,585)	(4,242)
Income tax expense	(52)	(385)	(246)
Net loss	$ (31,322)	$ (15,970)	$ (4,488)
Other financial data:			
Adjusted EBITDA	$ 54,503	$ 34,486	$ 24,019
Gross operating margin	121,595	93,546	71,640
Maintenance capital expenditures	5,777	3,353	5,193
Growth capital expenditures	114,982	90,510	164,623
Operating data:			
Average throughput of gas (MMBtu/d)[1]	884,259	622,238	570,599
Average volume of processed gas (MMBtu/d)	353,456	240,825	206,045
Average volume of NGLs fractionated (Bbls/d)	17,815	12,545	9,385
Realized prices on natural gas volumes ($/MMBtu)	$ 4.40	$ 3.75	$ 2.83
Realized prices on NGL volumes ($/gal)	0.78	0.88	0.87

(1) Current and historical average throughput volumes of natural gas per day include sales, transportation, fuel and shrink volumes for all periods presented. Historical average throughput volumes of natural gas per day presented previously included sales and transportation volume only.

The following table summarizes our average natural gas throughput volumes, amount of NGLs delivered, and volume of processed gas:

	Year Ended December 31,		
	2014	2013	2012
Average throughput volumes of natural gas (MMBtu/d)			
South Texas	689,180	422,775	369,964
Mississippi/Alabama	195,079	199,463	200,635
Total average throughput volumes of natural gas	884,259	622,238	570,599
Average volume of processed gas (MMBtu/d)	353,456	240,825	206,045
Average volume of NGLs fractionated (Bbls/d)	17,815	12,545	9,385

2014 Compared with 2013

Volume and overview. Our average throughput volume of natural gas increased by 262,021, or 42.1%, to 884,259 MMBtu/d during the year ended December 31, 2014, compared to 622,238 MMBtu/d for the year ended December 31, 2013, due primarily to increased gas volumes in South Texas from the TexStar Rich Gas System and Onyx acquisitions as well as increases in volume from new and existing customers in the Eagle Ford Shale producing area. Beginning in the second half of 2014 and continuing through the issuance of our financial statements, commodity prices have experienced increased volatility. In particular, crude oil and NGL prices have decreased significantly. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration of the commodities we sell or a material reduction in drilling in the geographic footprints in which we operate, including the Eagle Ford Shale region.

Processed gas volumes increased 112,631, or 46.8%, to 353,456 MMBtu/d during the year ended December 31, 2014, compared to 240,825 MMBtu/d during the year ended December 31, 2013. This increase was due primarily to increased volumes from the TexStar Rich Gas System Transaction and increases in volumes from new and existing customers in the Eagle Ford Shale producing area.

NGLs fractionated for the year ended December 31, 2014 averaged 17,815 Bbls/d, an increase of 5,270 Bbls/d, or 42.0%, compared to 12,545 Bbls/d for the year ended December 31, 2013. This increase was due primarily to the impact of additional volumes of rich gas on our system and enhanced operational efficiency at our facilities during the year ended December 31, 2014 compared to the year ended December 31, 2013.

Gross operating margin for the year ended December 31, 2014 was $121.6 million, compared to $93.5 million for the year ended December 31, 2013. This increase of $28.1 million, or 30.0%, was due primarily to increased processed gas volumes on our system, as well as increased transportation, gathering and processing fees.

Adjusted EBITDA increased by $20.0 million, or 58.0%, to $54.5 million for the year ended December 31, 2014, compared to $34.5 million for the year ended December 31, 2013, due to higher processed gas volumes and margins from processing and fractionation activities, partially offset by higher operating and general and administrative expenses. We had a net loss of $31.3 million for the year ended December 31, 2014 compared to a net loss of $16.0 million for the year ended December 31, 2013. Net loss increased due to higher overall expenses, including transaction-related costs affiliated with the Holdings Transaction and the TexStar Rich Gas System Transaction, and equity in losses of our joint venture investments, partially offset by higher gross operating margin.

Revenue. Our total revenues for 2014 increased 32.8% to $842.7 million compared to $634.7 million in 2013. This increase of $208.0 million was driven by acquisitions due primarily to greater revenue from sales of natural gas increasing of $125.7 million, greater revenues of NGLs and condensate of $56.7 million and higher revenue from transportation, gathering and processing fees of $25.6 million. Realized average natural gas and NGL prices were as follows:

	Years Ended December 31,	
	2014	2013
Natural Gas	$4.40/MMBtu	$3.75/MMBtu
NGLs	$ 0.78/gal	$ 0.88/gal

Cost of natural gas and NGLs sold. Our cost of natural gas and NGLs sold for the year ended December 31, 2014 was $721.1 million, compared to $541.2 million for the year ended December 31, 2013. This increase of $179.9 million, or 33.3%, was due primarily to increased natural gas volumes purchased, increased NGL volumes purchased and higher natural gas prices compared to the same period in 2013.

Operations and maintenance expenses. Operations and maintenance expenses for the year ended December 31, 2014 were $51.9 million, compared to $41.3 million for the year ended December 31, 2013. This increase of $10.6 million, or 25.8%, was due primarily to $3.0 million from higher labor costs including employee additions, $2.0 million from the accelerated vesting of our LTIP awards (which occurred as a result of our change of control in August 2014), higher fees of $1.5 million and higher operating costs of $1.4 million due to the acquisition of additional assets during the year ended December 31, 2014 compared to the year ended December 31, 2013.

General and administrative expenses. General and administrative expenses for the year ended December 31, 2014 were $32.4 million, compared to $21.8 million for the year ended December 31, 2013. This increase of $10.6 million, or 48.8%, was due primarily to increased expenses related to labor and benefits costs of $6.6 million from the accelerated vesting of LTIP awards (which occurred as a result of our change of control in August 2014), and $1.2 million from employee additions, together with higher professional fees of $2.5 million, mostly related to the TexStar Rich Gas System Transaction. Additionally, in the fourth quarter, the accrual for discretionary bonus was reduced after consideration of operating results.

Depreciation and amortization expense. Depreciation and amortization expense for the year ended December 31, 2014 was $42.2 million, compared to $33.5 million for the year ended December 31, 2013. The increase of $8.7 million, or 25.8%, was due primarily to depreciation of the TexStar Rich Gas System assets acquired in the third quarter of 2014 and other capital projects placed in service during 2014.

Equity in losses of joint venture investments. Our share of losses incurred by the joint venture investments acquired as part of the TexStar Rich Gas System assets was $6.5 million for the period from August 4, 2014 through December 31, 2014. We pay for our proportionate share of the joint ventures' operating costs, excluding depreciation and amortization through lease capacity payments. As a result, our share of the joint ventures' losses are primarily related to the joint ventures' depreciation and amortization.

Loss on extinguishment of debt. For the year ended December 31, 2014, we incurred a loss on the extinguishment of debt of $2.3 million in connection with the write-off of deferred financing costs related to exiting the Previous Credit Facility and entering into the Senior Credit Facilities in August 2014.

Interest expense. For the year ended December 31, 2014, interest expense was $15.6 million, compared to $12.6 million for the year ended December 31, 2013. This increase of $3.0 million, or 23.6%, was due to higher average borrowings related primarily to the debt incurred as part of the TexStar Rich Gas System.

2013 Compared with 2012

Volume and overview. Our average throughput volume of natural gas increased by 9.0% to 622,238 MMBtu/d during the year ended December 31, 2013, compared to 570,599 MMBtu/d during the year ended December 31, 2012, including an increase of 14.3% in our South Texas volumes. The increase was driven primarily by increased rich gas volumes entering our pipelines in South Texas to be processed at our facilities.

Processed gas volumes increased by 16.9% to 240,825 MMBtu/d during the year ended December 31, 2013, compared to 206,045 MMBtu/d during the year ended December 31, 2012 as a result of increased processing capacity during 2013 at our Woodsboro processing plant, which was completed during the last half of 2012.

NGLs fractionated for the year ended December 31, 2013 was 12,545 Bbls/d, an increase of 33.7%, compared to 9,385 Bbls/d for the year ended December 31, 2012. This was due primarily to an increase in rich gas volumes processed at our facilities from the Eagle Ford Shale area. Fractionation capacity of our Bonnie View fractionation facility increased from 11,500 Bbls/day during the last half of 2012 to 22,500 Bbls/day in February 2013.

Gross operating margin for the year ended December 31, 2013 was $93.5 million, compared to $71.6 million for the year ended December 31, 2012. This increase of $21.9 million, or 30.6%, was due primarily to increased margin from NGLs and revenues from transportation, gathering and processing fees related to higher processed gas volumes.

Adjusted EBITDA increased by $10.5 million, or 43.6%, to $34.5 million for the year ended December 31, 2013, compared to $24.0 million for the year ended December 31, 2012, due primarily to higher margins partially offset by higher operating and general and administrative expenses. We had a net loss of $16.0 million for the year ended December 31, 2013 compared to a net loss of $4.5 million for the year ended December 31, 2012. Net loss increased due primarily to an increase in depreciation and amortization expense, an increase in general and administrative expenses, an increase in interest expense and higher operating expenses, partially offset by higher gross margin.

Revenue. Our total revenues for the year ended December 31, 2013 were $634.7 million, compared to $496.1 million for the year ended December 31, 2012. This increase of $138.6 million, or 27.9%, was due primarily to revenue from sales of natural gas increasing by $79.8 million resulting from increased natural gas sales volumes. Revenue also increased from sales of NGLs and condensate by $45.4 million, or 36.6%, to $169.5 million for the year ended December 31, 2013, compared to $124.1 million for the year ended December 31, 2012, reflecting the increased production of NGLs at our facilities. Additionally, revenue from transportation, gathering and processing fees increased $13.3 million, or 28.8%, reflecting the results of additional rich gas volumes in 2013. Realized average natural gas and NGL prices were as follows:

	Years Ended December 31,	
	2013	2012
Natural Gas	$3.75/MMBtu	$2.83/MMBtu
NGLs	$ 0.88/gal	$ 0.87/gal

Cost of natural gas and NGLs sold. Our cost of natural gas and NGLs sold for the year ended December 31, 2013 was $541.2 million, compared to $424.5 million for the year ended December 31, 2012. The $116.7 million, or 27.5%, increase was due to higher prices of natural gas and NGLs purchased and increased volumes of natural gas purchased compared to 2012.

Operations and maintenance expenses. Operations and maintenance expenses for the year ended December 31, 2013 were $41.3 million, compared to $35.5 million for the year ended December 31, 2012. This increase of $5.7 million, or 16.1%, was due primarily to higher labor and benefits of $2.5 million, increased utility costs of $2.2 million associated with our Woodsboro plant and Bonnie View fractionation facility and increased ad valorem and other taxes of $1.5 million due to investments in and expansion of our assets, which were partially offset by a reduction in operating expenses of $1.2 million associated with the operations of our pipeline assets due to a reduction in scheduled maintenance during 2013.

General and administrative expenses. General and administrative expenses for the year ended December 31, 2013 were $21.8 million, compared to $13.8 million for the year ended December 31, 2012. This increase of $7.9 million, or 57.2%, was due primarily to increased expenses from employee additions, expenses related to being a newly public company, insurance coverage to support our growing asset base and operations and increased legal expenses.

Depreciation and amortization expense. Depreciation and amortization expense for the year ended December 31, 2013 was $33.5 million for 2013 compared to $19.0 million for the year ended December 31, 2012. This increase of $14.6 million, or 76.8%, was due primarily to the timing of the completion of growth capital projects and the acceleration of $1.3 million in depreciation related to the planned abandonment of a compressor station during 2013.

Loss on extinguishment of debt. For the year ended December 31, 2012, we incurred a loss on the extinguishment of debt of $1.8 million in connection with the repayment of $270.0 million of Southcross Energy LLC's assumed debt balance following our IPO consisting of a partial write-down of deferred financing costs.

Interest expense. For the year ended December 31, 2013, interest expense was $12.6 million, compared to $5.8 million for the year ended December 31, 2012. This increase of $6.8 million, or 118.3%, was due to higher average borrowings.

Liquidity and Capital Resources

Sources of Liquidity

Our primary sources of liquidity are cash generated from operations, cash raised through issuances of additional equity and debt securities and borrowings under our credit facilities. Our primary cash requirements consist of operating and maintenance and general and administrative expenses, growth and maintenance capital expenditures to sustain existing operations or generate additional revenues, interest payments on outstanding debt, purchases and construction of new assets, business acquisitions and distributions to unitholders.

We expect to fund short-term cash requirements, such as operating and maintenance and general and administrative expenses and maintenance capital expenditures, primarily through operating cash flows. We expect to fund long-term cash requirements, such as for expansion projects and acquisitions, through several sources, including operating cash flows, borrowings under our Senior Credit Facilities and issuances of additional debt and equity securities, as appropriate and subject to market conditions. See Note 8 to our consolidated financial statements.

Beginning in the second half of 2014 and continuing through the issuance of our financial statements, commodity prices have experienced increased volatility. In particular, crude oil and NGL prices have decreased significantly. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration of the commodities we sell or a material reduction in drilling in the geographic footprints in which we operate, including the Eagle Ford Shale region. See Note 2 to our consolidated financial statements.

As of March 2, 2015, we had $516.6 million in outstanding borrowings under our Senior Credit Facilities. Under our five-year revolving credit facility, pursuant to our Third A&R Revolving Credit Agreement, we have the ability to borrow up to $200.0 million (the "Credit Facility") less any letters of credit amounts outstanding, which as of March 2, 2015 provided us access to $104.9 million.

Capital expenditures. Our business is capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of and will continue to include:

- growth capital expenditures, which are capital expenditures to expand or increase the efficiency of the existing operating capacity of our assets. Growth capital expenditures include expenditures that facilitate an increase in volumes within our operations, but exclude expenditures for acquisitions; and
- maintenance capital expenditures, which are capital expenditures that are not considered growth capital expenditures.

The following table summarizes our capital expenditures (in thousands):

	Year Ended December 31, 2014	2013
Maintenance capital	$ 5,777	$ 3,353
Growth capital	114,982	90,510
Total Capital expenditures	$120,759	$93,863

Growth capital expenditures during the year ended December 31, 2014 related primarily to construction of the Webb Pipeline. The growth capital expenditures during year ended December 31, 2013 related primarily related to our Bonnie View NGL fractionation facility completed in February 2013 and our Bee Line pipeline completed in February 2013. Our growth capital expenditures in 2015 are estimated to be between $25 million and $30 million.

Outlook. Cash flow is affected by a number of factors, some of which we cannot control. These factors include prices and demand for our services, operational risks, volatility in commodity prices or interest rates, industry and economic conditions, conditions in the financial markets and other factors.

Our ability to benefit from growth projects to accommodate drilling activity and the associated need for infrastructure assets and services is subject to operational risks and uncertainties such as the uncertainty inherent in some of the assumptions underlying design specifications for new, modified or expanded facilities. These risks also impact third party service providers and their facilities. Delays or under-performance of our facilities or third party facilities may adversely affect our ability to generate cash from operations and comply with our obligations, including the covenants under our debt instruments. In other cases, actual production delivered may fall below volume estimates that we relied upon in deciding to pursue an acquisition or other growth project. Future cash flow and our ability to comply with our debt covenants would likewise be affected adversely if we experienced declining volumes over a sustained period and/or unfavorable commodity prices.

We believe that cash from operations, cash on hand, commitments from our Sponsors as discussed in Note 2 of the consolidated financial statements, and our unused borrowings under our Senior Credit Facilities will provide liquidity to meet future short-term capital requirements for a reasonable period of time. The sufficiency of these liquidity sources to fund necessary and committed capital needs will be dependent upon our ability to meet our covenant requirements of our Senior Credit Facilities. We believe we have and will continue to have sufficient liquidity to operate our business. See Notes 2 and 8 to our consolidated financial statements.

Growth projects and acquisitions are key elements of our business strategy. We intend to finance our growth capital primarily through the issuance of debt and equity. The timing, size or success of any acquisition or expansion effort and the associated potential capital commitments are unpredictable. To consummate acquisitions or capital projects, we may require access to additional capital. Our access to capital over the longer term will depend on our future operating performance, financial condition and credit rating and, more broadly, on the availability of equity and debt financing, which will be affected by prevailing conditions in our industry, the economy and the financial markets and other financial and business factors, many of which are beyond our control.

Cash Flows

The following table provides a summary of our cash flows by category (in thousands):

	Year Ended December 31, 2014	2013	2012
Net cash provided by operating activities	$ 48,335	$ 15,973	$ 24,323
Net cash used in investing activities	(240,570)	(97,109)	(169,816)
Net cash provided by financing activities	190,535	76,995	151,571

2014 Compared with 2013

Operating Activities—Net cash provided by operating activities was $48.3 million for the year ended December 31, 2014, compared to $16.0 million for the year ended December 31, 2013. The increase in cash provided by operating activities of $32.3 million was primarily the result of increased gross operating margin during the year ended December 31, 2014 compared to the year ended December 31, 2013. In addition, the net changes in working capital of $17.0 million caused an increase in operating cash flows for the year ended December 31, 2014 compared to the year ended December 31, 2013.

Investing Activities—Net cash used in investing activities was $240.6 million for the year ended December 31, 2014, compared to $97.1 million for the year ended December 31, 2013. The increase of $143.5 million primarily relates to the TexStar Rich Gas System Transaction in August 2014, the Onyx acquisition in March 2014 and increased capital expenditures in 2014.

Financing Activities—Net cash provided by financing activities was $190.5 million for the year ended December 31, 2014, compared to $77.0 million for the year ended December 31, 2013. The increase was due to proceeds received from our $144.7 million equity offering, net of expenses, in the first quarter of 2014, as well as additional net borrowings of $134.2 million from our debt instruments. The increase in cash provided by financing activities was partially offset by $100 million of debt assumed and immediately repaid by us in connection with the TexStar Rich Gas System Transaction, increased distributions paid of $16.7 million and additional financing costs of $15.6 million associated with the Senior Credit Facilities.

2013 Compared with 2012

Operating activities—Net cash provided by operating activities was $16.0 million for the year ended December 31, 2013, compared to $24.3 million for the year ended December 31, 2012. The decrease in cash provided by operating activities was $8.3 million. The net loss in 2013 was more than offset by non-cash charges in 2013, principally depreciation expense, resulting in positive cash flows from operations before working capital items of $22.4 million. Working capital needs were higher in 2013 due primarily to the 2013 payment of accrued capital expenditures in 2012 and an increased accounts receivable balance.

Investing activities—Net cash used in investing activities was $97.1 million for the year ended December 31, 2013, compared to $169.8 million for the year ended December 31, 2012. The decrease in cash used in investing activities of $72.7 million primarily related to the decrease in capital spending due to the completion of the Bee Line and Bonnie View fractionation facility in February 2013. In addition to capital spending, we spent $3.4 million, net of insurance proceeds and deductible, at our Gregory facility related to a fire that occurred in January 2013 to return the plant to service.

Financing activities—Net cash provided by financing activities was $77.0 million for the year ended December 31, 2013, compared to $151.6 million for the year ended December 31, 2012. The decrease was driven primarily by the proceeds of $187.8 million from the issuance of common units from our IPO and the proceeds of $42.8 million and $30.0 million from our Predecessor's issuance of Series B redeemable preferred units and Series C redeemable preferred units, respectively, during the year ended December 31, 2012. This was partially offset by an increase in net borrowings of $93.6 million and the issuance of our Series A Preferred Units for $38.8 million during the year ended December 31, 2013.

Senior Credit Facilities

On August 4, 2014, in connection with the consummation of the Holdings Transaction and acquisition of the TexStar Rich Gas System, we entered into the Senior Credit Facilities. See Note 8 to our consolidated financial statements.

The borrowings under our Credit Facility bear interest at the London Interbank Offered Rate ("LIBOR") or a base rate plus an applicable margin as defined in the Third A&R Revolving Credit Agreement. As of December 31, 2014, our margin was LIBOR plus 3.25% the outstanding balance of the Credit Facility was $30.0 million and the unused portion totaled $139.9 million.

The borrowings under our seven-year $450 million senior secured term loan facility (the “Term Loan”) under the Term Loan Credit Agreement bear interest at LIBOR plus 4.25% with a LIBOR floor of 1.00% or a base rate plus a margin as defined in that agreement. On August 4, 2014, the lenders funded the full amount of the Term Loan. As of December 31, 2014, the outstanding principal balance of the Term Loan was $445.6 million, net of original issuance discount of $2.1 million, and our borrowing rate was 5.25%. We are required to make quarterly amortization payments towards the Term Loan.

As of December 31, 2014, we were in compliance with the covenants set forth in the Senior Credit Facilities.

Series A Preferred Units

We entered into a Series A Convertible Preferred Unit Purchase Agreement with Southcross Energy LLC, pursuant to which we issued and sold 1,715,000 Series A Preferred Units to Southcross Energy LLC during the second quarter of 2013. Our total capital infusion of $40.0 million from all sales of Series A Preferred Units and General Partner capital contributions was used to reduce borrowings under our Credit Facility. The private placement of Series A Preferred Units resulted in proceeds to us of $39.2 million, and our General Partner contributed $0.8 million to maintain its 2.0% general partner interest in us.

On August 4, 2014, in connection with the Holdings Transaction and pursuant to the change in control provision in our Partnership Agreement applicable to our Series A Preferred Units, all holders of the Series A Preferred Units elected to convert their Series A Preferred Units into 2,015,638 common units based on the 110% exchange ratio specified in our Partnership Agreement.

Equity Distribution Agreement

On November 12, 2014, we established a $75 million “at-the-market” equity offering program pursuant to an equity distribution agreement (the “Distribution Agreement”) with Wells Fargo Securities, LLC, J.P. Morgan Securities LLC and RBC Capital Markets, LLC (each, a “Manager” and, collectively, the “Managers”). Under the Distribution Agreement, we may offer and sell up to $75 million in aggregate gross sales proceeds of our common units (the “Offered Units”) from time to time through the Managers, each as a sales agent for the Partnership. Sales of the Offered Units, if any, made under the Distribution Agreement will be made by means of ordinary brokers’ transactions on the New York Stock Exchange at market prices prevailing at the time of sale in block transactions, or as otherwise agreed upon by us and any Manager. The Offered Units have been registered under the Securities Act of 1933, as amended (the “Securities Act”), pursuant to Registration No. 333-192105, declared effective December 10, 2013, (the “Registration Statement”), including the prospectus contained therein, as supplemented by the prospectus supplement filed with the SEC on November 12, 2014. We intend to use the net proceeds from the sale of the Offered Units for general partnership purposes, including the repayment of debt, acquisitions and funding capital expenditures.

The Distribution Agreement contains customary representations, warranties and agreements by us, including our obligations to indemnify the Managers for certain liabilities under the Securities Act. The Managers and certain of their affiliates have engaged, and may in the future engage, in commercial and investment banking transactions with us in the ordinary course of their business for which they have received, and expect to receive, customary compensation and expense reimbursement. In particular, affiliates of each of the Managers are lenders under our Credit Facility, an affiliate of Wells Fargo Securities, LLC is a lender under our Term Loan and affiliates of the other sales agents may from time to time hold positions in the Term Loan. If we use any net proceeds of this offering to repay borrowings under our Credit Facility, such affiliates of the Managers will receive proceeds of the offering.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, except for our letters of credit under our Senior Credit Facilities described in Note 8 to our consolidated financial statements.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2014 (in thousands):

	Total	Less Than 1 Year	1-3 Years	3-5 Years
Long-term debt:				
Principal[(1)]	$475,629	$ 4,500	$ 9,000	$39,000
Interest[(2)]	85,863	21,922	43,845	20,096
Vehicle fleet lease	1,567	604	752	211
Office lease	4,450	1,141	2,254	1,055
Copiers	52	28	24	—
Total	$567,561	$28,195	$55,875	$60,362

(1) Contractual obligations related to the Credit Facility assume the $30.0 million outstanding as of December 31, 2014 is paid off at maturity in November 2019. Contractual obligations of the Term Loan are net of original issuance discount of $2.1 million.

(2) Interest is estimated at the weighted average interest rate for the year ended December 31, 2014 of 4.61% for periods through November 2019. The interest does not include interest rate swaps because they are considered to be immaterial.

Critical Accounting Policies

The accounting policies described below are considered critical to obtaining an understanding of our consolidated financial statements because their application requires significant estimates and judgments by management in preparing our consolidated financial statements. Management's estimates and judgments are inherently uncertain and may differ significantly from actual results achieved. Management considers an accounting estimate to be critical if the following conditions apply:

- the estimate requires significant assumptions; and
- changes in the estimate could have a material effect on our consolidated statements of operations or financial condition; or
- if different estimates that could have been selected had been used, there could be a material effect on our consolidated statements of operations or financial condition.

We have discussed the selection and application of these accounting estimates with the Audit Committee of the board of directors of our general partner and our independent registered public accounting firm. It is management's view that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions.

Revenue Recognition

Using the revenue recognition criteria of persuasive evidence of an exchange arrangement exists, delivery has occurred or services have been rendered and the price is fixed or determinable, we record natural gas and NGL revenue in the period when the physical product is delivered to the customer and in an amount based on the pricing terms of an executed contract. Our transportation, compression, processing, fractionation and other revenue is recognized in the period when the service is provided and includes our fee-based service revenue. In addition, collectability is evaluated on a customer-by-customer basis. New customers are subject to a credit review process, which evaluates the customers' financial position and their ability to pay.

Our sale and purchase arrangements are primarily accounted for on a gross basis in the statements of operations. These transactions are contractual arrangements that establish the terms of the purchase of natural gas or NGLs at a specified location and the sale of natural gas or NGLs at a different location on the same or on another specified date. These transactions require physical delivery and transfer of the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk.

Impairment of Long-Lived Assets

We evaluate our long-lived assets, which include finite-lived intangible assets, for impairment when events or circumstances indicate that their carrying values may not be recoverable. These events include, but are not limited to, market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, we evaluate the recoverability of our carrying value based on the long-lived asset's ability to generate future cash flows on an undiscounted basis. If the undiscounted cash flows are not sufficient to recover the long-lived asset's carrying value, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying values of the asset downward, if necessary, to their estimated fair value. Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted cash flows. With the recent decline in commodity prices negatively affecting the level of natural gas and crude oil production, we are more susceptible to potential impairment. During the year ended December 31, 2014, we recorded $1.6 million of impairment costs primarily related to right of way costs on a canceled project. At December 31, 2013 and 2012, we did not record any impairments of long-lived assets.

New Accounting Pronouncements

For a complete description of new accounting pronouncements, see Note 1 to our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate. Both profitability and cash flow are affected by volatility in the prices of these commodities. Natural gas and NGL prices are impacted by changes in the supply and demand for natural gas and NGLs, as well as market uncertainty, particularly in the depressed energy pricing environment that began in the second half of 2014. Adverse effects on cash flow from increases or reductions in natural gas and NGL product prices could adversely affect our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of the commercial terms of our contract portfolio by entering into fixed-fee-based or fixed-spread arrangements whenever possible and the use of swing swaps. Swing swaps are generally short-term in nature (one month) and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. We have not entered into any long-term derivative contracts to manage exposure to commodity price risk. Natural gas and NGL prices, however, also can affect profitability indirectly by influencing the level of drilling activity in our areas of operation. We are a net seller of NGLs and, as such, financial results also are exposed to fluctuations in NGL price levels.

A hypothetical increase or decrease in commodity prices by 1.0% would have changed our gross operating margin by $24.0 thousand and $0.3 million for the years ended December 31, 2014 and 2013, respectively.

Interest Rate Risk

We have exposure to changes in interest rates on indebtedness. We manage our exposure to interest rate fluctuations by entering into interest rate derivative instruments that include interest rate swaps, caps and floors. These contracts reduce our exposure to interest rate volatility and result in primarily fixed rate debt when considering the combination of the variable rate debt and the interest rate derivative instrument.

Under the terms of our interest rate swap agreements, we receive a floating rate based upon LIBOR and pay a fixed rate. In March 2012, our Predecessor entered into an interest rate swap contract for $150.0 million notional amount of debt, which was transferred to us in conjunction with our IPO. Under the terms of the swap, we received a floating rate based upon one-month LIBOR and paid a fixed ratio of 0.54% through June 30, 2014. In 2014, we entered into interest rate swap contracts with a weighted average fixed rate of 0.69% to reduce our exposure to interest rate volatility on $240.0 million notional amount of debt, of which $140.0 million will mature in 2015 and $100.0 million will mature in 2016.

In December 2014, we entered into an interest rate cap contract for $20.0 million notional amount of debt with a maturity date of December 31, 2016. The contract effectively caps our LIBOR-based interest rate on that portion of debt at 1.5%.

A hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $0.7 million and $0.9 million for the years ended December 31, 2014 and 2013, respectively.

Risk Relating to NGLs

Recovery Commitments

We have operational exposure under several gas supply and transportation agreements that contain fixed percentage NGL recovery obligations. To the extent that we do not produce, sell or re-deliver under transportation agreements at least as many gallons of NGLs as required under those respective supply and transportation agreements, we are exposed to the equivalent replacement cost of the respective NGL products at NGL market prices net of contractual discounts, offset by the value of the unrecovered NGL products sold at methane natural gas prices. Similarly, to the extent that we produce, sell or re-deliver more gallons of NGL under transportation agreements than required under these agreements, we are able to sell the excess NGL products for our own account.

A hypothetical increase or decrease in NGL volumes recovered of 1.0% would have changed our gross operating margin by $1.1 million and $1.1 million for the years ended December 31, 2014 and 2013, respectively.

Pricing Differential

We are exposed to the risk that we will be unable to sell NGLs at the expected differential to index prices necessary to preserve fixed-spread margins. To the extent that we do not produce marketable purity NGL products, due to operational disruptions or NGL market disruptions, we could realize lower than expected differentials to index prices. This risk is managed by monitoring the supply and demand of our markets, as well as the pricing indices relevant to our products.

A hypothetical increase or decrease of $0.01 in our realized NGL gross operating margin spread per gallon would have changed our gross operating margin by $2.9 million and $1.9 million for the years ended December 31, 2014 and 2013, respectively.

Credit Risk

We are subject to risk of loss resulting from nonpayment by our customers to whom we provide midstream services or sell natural gas or NGLs. Our credit exposure related to these customers is represented by the value of our trade receivables. Where exposed to a significant credit risk, we analyze the customer’s financial condition prior to entering into a transaction or agreement, establish credit terms and monitor the appropriateness of these terms on an ongoing basis. In the event of a customer default, we may sustain a loss and our cash receipts could be negatively impacted.

Item 8. Financial Statements and Supplementary Data

SOUTHCROSS ENERGY PARTNERS, L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Southcross Energy Partners GP, LLC and the unitholders of Southcross Energy Partners, L.P.

Dallas, Texas

We have audited the accompanying balance sheets of Southcross Energy Partners, L.P., and subsidiaries (the "Partnership") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), partners' capital and members' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Partnership has obtained support from the owners of Southcross Holdings GP LLC, which controls the General Partner of the Partnership, in order to maintain the compliance with the financial covenants of the Partnership. Also, as discussed in Notes 1 and 3 to the financial statements, the Partnership acquired the TexStar Rich Gas System on August 4, 2014.

/s/ Deloitte & Touche LLP

Dallas, Texas

March 6, 2015

SOUTHCROSS ENERGY PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands, except for unit data)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,649	$ 3,349
Trade accounts receivable	71,159	57,669
Accounts receivable—affiliates	11,325	—
Prepaid expenses	3,073	3,061
Other current assets	1,813	5,105
Total current assets	89,019	69,184
Property, plant and equipment, net	968,810	575,795
Intangible assets, net	1,511	1,568
Investments in joint ventures	147,098	—
Other assets	17,189	5,768
Total assets	$1,223,627	$652,315
LIABILITIES, PREFERRED UNITS AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 103,188	$ 62,451
Accounts payable—affiliates	12,856	—
Current portion of long-term debt	4,500	—
Other current liabilities	11,061	5,344
Total current liabilities	131,605	67,795
Long-term debt	471,129	267,300
Other non-current liabilities	1,109	1,692
Total liabilities	603,843	336,787
Commitments and contingencies (Note 9)		
Series A convertible preferred units (1,769,915 units issued and outstanding as of December 31, 2013)	—	40,504
Partners' capital:		
Common units (23,800,943 and 12,253,985 units outstanding as of December 31, 2014 and 2013, respectively)	259,735	169,141
Class B Convertible units (14,889,078 units issued and outstanding as of December 31, 2014)	298,833	—
Subordinated units (12,213,713 units outstanding as of December 31, 2014 and 2013)	48,831	99,726
General Partner interest	12,385	6,367
Accumulated other comprehensive loss	—	(210)
Total partners' capital	619,784	275,024
Total liabilities, preferred units and partners' capital	$1,223,627	$652,315

See accompanying notes to these consolidated financial statements.

SOUTHCROSS ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except for unit and per unit data)

	Year Ended December 31,		
	2014	2013	2012
Revenues:			
Revenues (Note 15)	$ 829,460	$ 634,722	$ 496,129
Revenues—affiliates	13,267	—	—
Total revenues	842,727	634,722	496,129
Expenses:			
Cost of natural gas and liquids sold	721,132	541,176	424,489
Operations and maintenance	51,902	41,254	35,532
Depreciation and amortization	42,206	33,548	18,977
General and administrative	32,385	21,764	13,842
Impairment of assets	1,556	—	—
Loss (gain) on sale of assets	365	(25)	—
Total expenses	849,546	637,717	492,840
(Loss) income from operations	(6,819)	(2,995)	3,289
Other (expense) income:			
Equity in losses of joint venture investments	(6,496)	—	—
Interest expense	(15,562)	(12,590)	(5,767)
Loss on extinguishment of debt	(2,316)	—	(1,764)
Other expense	(77)	—	—
Total other expense	(24,451)	(12,590)	(7,531)
Loss before income tax expense	(31,270)	(15,585)	(4,242)
Income tax expense	(52)	(385)	(246)
Net loss	$ (31,322)	$ (15,970)	$ (4,488)
Series A Preferred fair value adjustment	(4,596)	(37)	—
Series A Preferred unit in-kind distribution	(534)	(1,633)	0
General partner unit in-kind distribution	(207)	—	0
Net loss from January 1, 2012 through November 6, 2012	—	—	260
Net loss attributable to partners	$ (36,659)	$ (17,640)	$ (4,228)
Net loss from January 1, 2012 through November 6, 2012			(260)
Less deemed dividends on:			
Redeemable preferred units			(2,693)
Series B redeemable preferred units			(4,696)
Series C redeemable preferred units			(2,012)
Preferred units			(13,249)
Net loss attributable to Southcross Energy LLC common unitholders Earnings per unit:			$ (22,910)
Net loss allocated to limited partner common units	$ (20,175)	$ (8,683)	$ (2,072)
Weighted average number of limited partner common units outstanding	21,641,635	12,224,997	12,213,713
Basic and diluted loss per common unit	$ (0.93)	$ (0.71)	$ (0.17)
Distributions declared per common unit	$ 1.60	$ 1.60	0.24
Net loss allocated to limited partner subordinated units	$ (8,355)	$ (8,638)	$ (2,071)
Weighted average number of limited partner subordinated units outstanding	12,213,713	12,213,713	12,213,713
Basic and diluted loss per subordinated unit	$ (0.68)	$ (0.71)	$ (0.17)
Net loss allocated to Southcross Energy LLC common units			$ (22,910)
Weighted average number of Southcross Energy LLC common units outstanding			1,198,429
Basic and diluted net loss per Southcross Energy LLC common unit			$ (19.12)

See accompanying notes to these consolidated financial statements.

SOUTHCROSS ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Year Ended December 31,		
	2014	2013	2012
Net loss	$(31,322)	$(15,970)	$(4,488)
Other comprehensive income (loss):			
Hedging losses reclassified to earnings and recognized in interest expense	221	415	268
Adjustment in fair value of derivatives	(11)	(148)	(745)
Total other comprehensive income (loss)	210	267	(477)
Comprehensive loss	$(31,112)	$(15,703)	$(4,965)

See accompanying notes to these consolidated financial statements.

SOUTHCROSS ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net loss	$ (31,322)	$ (15,970)	$ (4,488)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation and amortization	42,206	33,548	18,977
Unit-based compensation	10,074	2,186	630
Loss on extinguishment of debt	2,316	—	1,764
Amortization of deferred financing costs	2,005	1,287	1,183
Loss (gain) on sale of assets, net	365	(25)	—
Unrealized loss (gain) on financial instruments	168	(120)	141
Equity in losses of joint venture investments	6,496	—	—
Impairment of assets	1,556	—	—
Other, net	65	130	—
Changes in operating assets and liabilities:			
Trade accounts receivable, including affiliates	(22,695)	(6,675)	(9,760)
Prepaid expenses and other current assets	(5)	(1,197)	(1,246)
Other non-current assets	(29)	215	1,786
Accounts payable and accrued liabilities	34,480	1,411	16,517
Other liabilities, including affiliates	2,655	1,183	(1,181)
Net cash provided by operating activities	48,335	15,973	24,323
Cash flows from investing activities:			
Capital expenditures	(120,759)	(93,863)	(169,816)
Expenditures for assets subject to property damage claims, net of insurance proceeds and deductibles	2,706	(3,383)	—
Investment contribution to joint venture investments	(148)	—	—
TexStar Rich Gas System acquisition from affiliate	(79,955)	—	—
Other acquisitions	(44,038)	—	—
Proceeds from sale of assets	1,624	137	—
Net cash used in investing activities	(240,570)	(97,109)	(169,816)
Cash flows from financing activities:			
Proceeds from issuance of common units, net	144,671	—	187,764
Borrowings under our credit facility	244,500	129,300	297,500
Borrowings under our term loan agreement	450,000	—	—
Repayments under our credit facility	(481,800)	(53,000)	(314,780)
Repayments under our term loan agreement	(2,250)	—	—
Payments on capital lease obligations	(599)	(542)	—
Financing costs	(17,777)	(2,139)	(5,178)
Proceeds from issuance of Series A convertible preferred units, net of issuance costs	—	38,832	—
Contributions from general partner	9,967	800	—
Repurchase and retirement of Southcross Energy LLC common units	—	—	(15,300)
Proceeds from issuance of Southcross Energy LLC Series B redeemable preferred units	—	—	42,800
Proceeds from issuance of Southcross Energy LLC Series C redeemable preferred units	—	—	30,000
Distributions to Southcross Energy LLC	—	—	(46,030)
Purchase and retirement of Partnership common units	—	—	(25,205)
Payments of distributions and distribution equivalent rights	(52,645)	(35,992)	—
Assumption and repayment of debt in TexStar Rich Gas System Transaction	(100,000)	—	—
Tax withholdings on unit-based compensation vested units	(3,532)	(264)	—
Net cash provided by financing activities	190,535	76,995	151,571
Net (decrease) increase in cash and cash equivalents	(1,700)	(4,141)	6,078
Cash and cash equivalents—Beginning of year	3,349	7,490	1,412
Cash and cash equivalents—End of year	$ 1,649	$ 3,349	$ 7,490

See accompanying notes to these consolidated financial statements.

SOUTHCROSS ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL AND MEMBERS' EQUITY
(In thousands)

	Partners' Capital					Southcross Energy LLC Members' Equity			
	Limited Partners								
	Common	Class B Convertible	Subordinated	General Partner	Accumulated Other Comprehensive Loss	Common Class A	Common Class B	Accumulated Deficit	Total
BALANCE—December 31, 2011	**$ —**	**$—**	**$ —**	**$ —**	**$ —**	**$ 1,416**	**$ 57**	**$(11,638)**	**$ (10,165)**
Net loss attributable to period January 1, 2012 through November 6, 2012	—	—	—	—	—	—	—	(260)	(260)
Issuance of common units, net	187,764	—	—	—	—	—	—	—	187,764
Unit-based compensation on long-term incentive plan	192	—	—	—	—	—	—	—	192
Deemed dividend on:									
Redeemable preferred units	—	—	—	—	—	—	—	(2,693)	(2,693)
Series B redeemable preferred units	—	—	—	—	—	—	—	(4,696)	(4,696)
Series C redeemable preferred units	—	—	—	—	—	—	—	(2,012)	(2,012)
Preferred units	—	—	—	—	—	—	—	(13,249)	(13,249)
Repurchase and retirement of Southcross Energy LLC common units	—	—	—	—	—	(131)	—	(15,169)	(15,300)
Contribution by Southcross Energy LLC	43,274	—	164,464	6,713	—	(1,285)	(57)	49,717	262,826
Distributions to Southcross Energy LLC	(9,589)	—	(36,441)	—	—	—	—	—	(46,030)
Net loss attributable to period November 7, 2012 through December 31, 2012	(2,072)	—	(2,071)	(85)	—	—	—	—	(4,228)
Purchase and retirement of Partnership common units	(25,205)	—	—	—	—	—	—	—	(25,205)
Net effect of cash flow hedges	—	—	—	—	(477)	—	—	—	(477)
BALANCE—December 31, 2012	**$194,364**	**$—**	**$125,952**	**$6,628**	**$(477)**	**$ —**	**$ —**	**$ —**	**$326,467**
Net loss	(7,829)	—	(7,822)	(319)	—	—	—	—	(15,970)
Unit-based compensation on long-term incentive plan	1,601	—	—	—	—	—	—	—	1,601
Series A convertible preferred unit in-kind distribution and fair value adjustments	(838)	—	(799)	(33)	—	—	—	—	(1,670)
Contributions from general partner	—	—	—	800	—	—	—	—	800
Cash distributions paid	(17,597)	—	(17,589)	(742)	—	—	—	—	(35,928)
Accrued distribution equivalent rights on long-term incentive plan	(279)	—	—	—	—	—	—	—	(279)
Tax withholdings on unit-based compensation vested units	(264)	—	—	—	—	—	—	—	(264)
General partner unit in-kind distribution	(17)	—	(16)	33	—	—	—	—	—
Net effect of cash flow hedges	—	—	—	—	267	—	—	—	267
BALANCE—December 31, 2013	**$169,141**	**$—**	**$ 99,726**	**$6,367**	**$(210)**	**$ —**	**$ —**	**$ —**	**$275,024**

SOUTHCROSS ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL AND MEMBERS' EQUITY (Continued)

(In thousands)

	Partners' Capital					Southcross Energy LLC Members' Equity			
	Limited Partners								
	Common	Class B Convertible	Subordinated	General Partner	Accumulated Other Comprehensive Loss	Common Class A	Common Class B	Accumulated Deficit	Total
Net loss	(15,155)	(7,436)	(8,105)	(626)	—	—	—	—	(31,322)
Issuance of common units, net	144,671	—	—	—	—	—	—	—	144,671
Issuance of Class B Convertible units, net	—	324,413	—	—	—	—	—	—	324,413
Consideration paid in excess of the net book value of the TexStar Rich Gas System	(45,420)	(27,925)	(23,308)	(1,972)	—	—	—	—	(98,625)
Class B Convertible unit in-kind distribution	(6,209)	9,610	(3,193)	(208)	—	—	—	—	—
Unit-based compensation on long-term incentive plan	9,947	—	—	—	—	—	—	—	9,947
Series A convertible preferred conversion into common units	45,624	—	—	—	—	—	—	—	45,624
Series A convertible preferred unit in-kind distribution and fair value adjustments	(3,126)	—	(1,897)	(107)	—	—	—	—	(5,130)
Contributions from general partner	809	171	345	9,991	—	—	—	—	11,316
Cash distributions and distribution equivalent rights paid	(36,706)	—	(14,657)	(1,282)	—	—	—	—	(52,645)
Accrued distribution equivalent rights on long-term incentive plan	(167)	—	—	—	—	—	—	—	(167)
Tax withholdings on unit-based compensation vested units	(3,532)	—	—	—	—	—	—	—	(3,532)
General partner unit in-kind distribution	(142)	—	(80)	222	—	—	—	—	—
Net effect of cash flow hedges	—	—	—	—	210	—	—	—	210
BALANCE—December 31, 2014	**$259,735**	**$298,833**	**$ 48,831**	**$12,385**	**$ —**	**$—**	**$—**	**$—**	**$619,784**

See accompanying notes to these consolidated financial statements.

SOUTHCROSS ENERGY PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Organization

Southcross Energy Partners, L.P. (the "Partnership," "Southcross," "we," "our" or "us") is a Delaware limited partnership formed in April 2012. Southcross Energy LLC is a Delaware limited liability company, and the predecessor for accounting purposes (the "Predecessor") of the Partnership. References in this Form 10-K to the Partnership, when used for periods prior to our initial public offering ("IPO") on November 7, 2012, refer to Southcross Energy LLC and its consolidated subsidiaries, unless otherwise specifically noted. References in this Form 10-K to the Partnership, when used for periods beginning at or following our IPO, refer collectively to the Partnership and its consolidated subsidiaries. Until August 4, 2014, Southcross Energy LLC held all of the equity interests in Southcross Energy Partners GP, LLC, a Delaware limited liability company and our general partner ("General Partner"), all of our subordinated units, as well as a portion of our common units and Series A Convertible Preferred Units ("Series A Preferred Units"). Southcross Energy LLC is controlled through investment funds and entities associated with Charlesbank Capital Partners, LLC ("Charlesbank").

On August 4, 2014, Southcross Energy LLC and TexStar Midstream Services, LP ("TexStar") combined pursuant to a contribution agreement in which Southcross Holdings LP, a Delaware limited partnership ("Holdings"), was formed (the "Holdings Transaction"). As a result of the Holdings Transaction, Holdings owns 100% of our General Partner (and therefore controls us), all of our subordinated units and a portion of our common units. Charlesbank, EIG Global Energy Partners, LLC ("EIG") and Tailwater Capital LLC ("Tailwater") (collectively, the "Sponsors") each indirectly own approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine Opportunities Fund and GE Energy Financial Services own certain additional ownership interests in Holdings as well.

Initial Public Offering

On November 7, 2012, we completed our IPO. As the series of transactions described in Note 12 relate to entities under common control, these consolidated financial statements reflect the assets, liabilities, statements of operations and cash flows of us beginning November 7, 2012 and of our Predecessor as of and for the periods ending prior to November 7, 2012.

Description of Business

We are a master limited partnership that provides natural gas gathering, processing, treating, compression and transportation services and NGL fractionation and transportation services. We also source, purchase, transport and sell natural gas and NGLs. Our assets are located in South Texas, Mississippi and Alabama and include four gas processing plants, two fractionation facilities and approximately 3,005 miles of pipeline. We are headquartered in Dallas, Texas.

Segments

Our chief operating decision-maker is our Chief Executive Officer who reviews financial information presented on a consolidated basis in order to assess our performance and make decisions about resource allocations. There are no segment managers who are held accountable by the chief operating decision-maker, or anyone else, for operations, operating results and planning for levels or components below the consolidated unit level. Accordingly, we have determined that we have one reportable segment.

Basis of Presentation

The accompanying consolidated financial statements and related notes present the consolidated balance sheets as of December 31, 2014 and 2013 and the consolidated statements of operations, comprehensive income

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

(loss), cash flows and changes in partners' capital and members' equity for the years ended December 31, 2014, 2013 and 2012 (See Note 2). As a result of our IPO, there was no change in the accounting basis of the contributed net assets of Southcross Energy LLC. Information included in these financial statements and related notes are presented as if we and Southcross Energy LLC were the same entity, except with respect to associated changes in capitalization as described in Note 12.

The consolidated financial statements reflect the assets acquired and liabilities assumed and the related operating results beginning on March 6, 2014 associated with the Onyx pipelines acquisition as discussed further in Note 3. The consolidated financial statements also reflect the TexStar Rich Gas System Transaction and the related operating results beginning on August 4, 2014, as discussed further in Note 3.

As a result of the Holdings Transaction, Holdings acquired a controlling equity interest in the Partnership which is being accounted for under the acquisition method of accounting in the consolidated financial statements of Holdings, whereby Holdings recorded the Partnership's assets acquired and liabilities assumed at fair value. However, because less than 80% of the equity interests in the Partnership were acquired, push down accounting of Holdings' basis in the Partnership was prohibited in our consolidated financial statements.

Additionally, because the TexStar Rich Gas System was owned by TexStar, the Partnership recorded the TexStar Rich Gas System at TexStar's historical cost. Thus, the difference between consideration paid and the TexStar Rich Gas System's historical cost (net book value) at August 4, 2014, the date on which the Holdings Transaction and the TexStar Rich Gas System Transaction closed, was recorded as a reduction to partners' capital. Management concluded that the Partnership was the predecessor for accounting purposes for periods prior to August 4, 2014.

The accompanying consolidated financial statements were prepared in accordance with accounting principles generally accepted in the U.S. ("GAAP") and in accordance with the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). Our consolidated financial statements include the accounts of Southcross and its 100% owned subsidiaries. We eliminate all intercompany balances and transactions in preparing consolidated financial statements.

Principles of Consolidation

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. We do not have ownership in any consolidated variable interest entities.

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make various estimates and assumptions that may affect the amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results may differ from those estimates.

Significant Accounting Policies

Revenue Recognition

Using the revenue recognition criteria of persuasive evidence of an exchange arrangement exists, delivery has occurred or services have been rendered and the price is fixed or determinable, we record natural gas and

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

NGL revenue in the period when the physical product is delivered to the customer and in an amount based on the pricing terms of an executed contract. Our transportation, compression, processing, fractionation and other revenue is recognized in the period when the service is provided and includes our fee-based service revenue. In addition, collectability is evaluated on a customer-by-customer basis. New customers are subject to a credit review process, which evaluates the customers' financial position and their ability to pay.

Our sale and purchase arrangements are primarily accounted for on a gross basis in the statements of operations. These transactions are contractual arrangements that establish the terms of the purchase of natural gas or NGLs at a specified location and the sale of natural gas or NGLs at a different location on the same or on another specified date. These transactions require physical delivery and transfer of the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk.

We derive revenue in our business from the following types of arrangements:

- ***Fixed-Fee.*** We receive a fixed-fee per unit of natural gas volume that we gather at the wellhead, process, treat, compress and/or transport for our customers, or we receive a fixed-fee per unit of NGL volume that we fractionate. Some of our arrangements also provide for a fixed-fee for guaranteed transportation capacity on our systems.
- ***Fixed-Spread.*** Under these arrangements, we purchase natural gas and NGLs from producers or suppliers at receipt points on our systems at an index price plus or minus a fixed price differential and sell these volumes of natural gas and NGLs at delivery points off our systems at the same index price, plus or minus a fixed price differential. By entering into such back-to-back purchases and sales, we are able to mitigate our risk associated with changes in the general commodity price levels of natural gas and NGLs. We remain subject to variations in our fixed-spreads to the extent we are unable to precisely match volumes purchased and sold in a given time period or are unable to secure the supply or to produce or market the necessary volume of products at our anticipated differentials to the index price.
- ***Commodity-Sensitive.*** In exchange for our processing services, we may remit to a customer a percentage of the proceeds from our sales, or a percentage of the physical volume, of residue natural gas and/or NGLs that result from our natural gas processing, or we may purchase NGLs from customers at set fixed NGL recoveries and retain the balance of the proceeds or physical commodity for our own account. These arrangements are generally combined with fixed-fee and fixed-spread arrangements for processing services and, therefore, represent only a portion of a processing contract's value. The revenues we receive from these arrangements directly correlate with fluctuating general commodity price levels of natural gas and NGLs and the volume of NGLs recovered relative to the fixed recovery obligations.

Long-Lived Assets

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead and the cost of financing construction. Costs associated with obtaining rights of way agreements and easements to facilitate the building and maintenance of new pipelines are capitalized and depreciated over the life of the associated pipeline. We capitalize major units of property replacements or improvements and expense minor items. We use the straight-line method to depreciate property, plant and

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

equipment over the estimated useful lives of the assets. We depreciate leasehold improvements and capital lease assets over the shorter of the life of the asset or the life of the lease. Maintenance and repairs are charged directly to expense.

Our intangible assets consist of acquired long-term supply and gas gathering contracts. We amortize these contracts on a straight-line basis over the 30-year expected useful lives of the contracts.

Impairment of Long-Lived Assets

We evaluate our long-lived assets, which include finite-lived intangible assets, for impairment when events or circumstances indicate that their carrying values may not be recoverable. These events include, but are not limited to, market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, we evaluate the recoverability of our carrying value based on the long-lived asset's ability to generate future cash flows on an undiscounted basis. If the undiscounted cash flows are not sufficient to recover the long-lived asset's carrying value, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying values of the asset downward, if necessary, to their estimated fair value. Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted cash flows. With the recent decline in commodity prices negatively affecting the level of natural gas and crude oil production, we are more susceptible to potential impairment. During the year ended December 31, 2014, we recorded $1.6 million of impairment costs primarily related to right of way costs on a canceled project. We did not record any impairments during the years ended 2013 and 2012.

Capitalization of Interest Cost

We capitalize interest on projects during their construction period. Once a project is placed in service, capitalized interest, as a component of the total cost of the construction, is depreciated over the estimated useful life of the asset constructed.

We incurred the following interest costs (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Total interest costs	$18,326	$14,047	$12,035
Capitalized interest included in property, plant and equipment, net	(2,764)	(1,457)	(6,268)
Interest expense	$15,562	$12,590	$ 5,767

Cash and Cash Equivalents

We consider all short-term investments with an original maturity of three months or less to be cash equivalents. At December 31, 2014 and 2013, except for amounts held in bank accounts to cover current payables, all of our cash equivalents were invested in short-term money market accounts and overnight sweep accounts.

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Allowance for Doubtful Accounts

In evaluating the collectability of our accounts receivable, we perform credit evaluations of our new customers and adjust payment terms based upon payment history and each customer's current creditworthiness, as determined by our review of such customer's credit information. We extend credit on an unsecured basis to many of our customers. At December 31, 2014 and 2013, we have recorded no allowance for uncollectible accounts receivable.

Deferred Financing Costs

Deferred financing costs are capitalized and amortized as interest expense under the effective interest method over the term of the related debt. The unamortized balance of deferred financing costs is included in other assets on the consolidated balance sheets. Changes in deferred financing costs are as follows (in thousands):

	Year Ended December 31,	
	2014	2013
Deferred financing costs, January 1	$ 5,237	$ 4,385
Capitalization of deferred financing costs[1]	15,659	2,139
Amortization of deferred financing costs[2]	(4,321)	(1,287)
Deferred financing costs, December 31	$16,575	$ 5,237

(1) See Note 8.

(2) This amount includes $2.3 million written off in connection with repayment of the Previous Credit Facility (as defined in Note 8) and contemporaneously entering into the Senior Credit Facilities (as defined in Note 8) in August 2014.

Asset Retirement Obligations

We evaluate whether any future asset retirement obligations ("AROs") exist and estimate the costs for such AROs for certain future events. An ARO will be recorded in the periods where we can reasonably determine the settlement dates or the period in which the expense is incurred and an estimated cost of the retirement obligation. Generally we do not have the intention of discontinuing the use of any significant assets or have a legal obligation to do so. Therefore, in these situations we do not have sufficient information to reasonably estimate any future AROs. However, during the year ended December 31, 2013, an asset retirement obligation of $0.5 million related to the discontinued use of an asset was recorded in operations and maintenance expense. This ARO is substantially complete and we do not expect significant additional costs. No AROs were recorded for the years ended December 31, 2014.

Environmental Costs and Other Contingencies

We recognize liabilities for environmental and other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and no specific amount in that range is more likely than any other, the low end of the range is accrued. No amounts were recorded as of December 31, 2014 and 2013.

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Fair Value of Financial Instruments

Accounting guidance requires the disclosure of the fair value of all financial instruments that are not otherwise recorded at fair value in the financial statements. At December 31, 2014 and 2013, financial instruments recorded at contractual amounts that approximate fair value include certain funds on deposit, accounts receivable, other receivables and accounts payable and accrued liabilities. The fair values of such items are not materially sensitive to shifts in market interest rates because of the short term to maturity of these instruments (See Note 6).

The fair value of the debt funded through our Credit Facility approximates its carrying amount as of December 31, 2014 and 2013 due primarily to the variable nature of the interest rate of the instrument and is considered a Level 2 fair value measurement (See Note 6).

Derivative Instruments

In our normal course of business, we enter into month-ahead commodity swap contracts in order to hedge economically our exposure to certain intra-month natural gas index pricing risk. We manage our interest rate risk through interest rate swaps and interest rate caps (See Note 6).

Derivative financial instruments are recorded in the consolidated balance sheets at fair value, except for derivative contracts that we qualify for and for which we have elected the normal purchase or normal sale exceptions, which are not reflected in the consolidated balance sheets or statements of operations prior to accrual of the settlement. We present our derivative assets and liabilities on a net basis.

If certain criteria are met, a derivative financial instrument may be designated as a fair value hedge or cash flow hedge.

The changes in fair value of cash flow hedges are deferred in accumulated other comprehensive loss, net of tax, to the extent the contracts are, or have been, effective as hedges, until the forecasted transactions impact earnings. The ineffective portion of changes in fair value of cash flow hedges is recognized immediately into earnings.

On an ongoing basis, a derivative instrument designated as a cash flow hedge must be highly effective in offsetting changes in cash flows of the hedged item. If it is determined that the derivative instrument is not highly effective as a hedge, hedge accounting will be discontinued prospectively. Changes in fair value of the associated hedging instrument are then recognized immediately in earnings for the remainder of the contract term unless a new hedging relationship is designated. The assessment of effectiveness excludes counterparty default risk and our own non-performance risk. The effect of these valuation adjustments was immaterial for the years ended December 31, 2014 and 2013.

Derivative financial instruments designated as cash flow hedges must have a high correlation between price movements in the derivative and the hedged item. If and when an acceptable level of correlation no longer exists, hedge accounting ceases and changes in fair value are recognized in our statements of operations. If it becomes probable that a forecasted transaction will not occur, we immediately recognize the related deferred gains or losses in our statements of operations. Changes in fair value of the associated hedging instrument are then recognized immediately in earnings for the remainder of the contract term unless a new hedging relationship is designated.

In March 2012, we entered into an interest rate swap to reduce the risks with respect to the variability of the interest rates under our Previous Credit Facility. In February 2014, we discontinued cash flow hedge accounting

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

on a prospective basis as a result of the repayment of borrowings under our Previous Credit Facility (See Note 8). With the exception of these interest rate swaps, we did not have any other derivative financial instruments designated as fair value or cash flow hedges for accounting purposes during the years ended December 31, 2014 and 2013.

For our derivative financial instruments that have not been designated as cash flow hedges for accounting purposes, changes in such instruments' fair values are recognized immediately in earnings. We do not hold or issue financial instruments or derivative financial instruments for trading purposes.

Unit-Based Compensation

Unit-based awards which settle in common units are classified as equity and are recognized in the financial statements over the vesting period at their grant date fair value. Unit-based awards which settle in cash are classified as liabilities and remeasured at every balance sheet date through settlement, such that the vested portion of the liability is adjusted to reflect its revised fair value through compensation expense. Currently, all awards granted under the long-term incentive plan will be settled in common units. Compensation expense associated with unit-based awards, adjusted for forfeitures, is recognized evenly from the date of the grant over the vesting period within general and administrative expenses on our consolidated statements of operations.

Income Taxes

No provision for federal or state income taxes, except as noted below, is included in our statements of operations as such income is taxable directly to our partners. Each partner is responsible for its share of federal and state income tax. Net earnings for financial statement purposes may differ significantly from taxable income reportable to each partner as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

We are subject to the Texas margin tax which qualifies as an income tax under GAAP that requires us to recognize the impact of this tax on the temporary differences between the financial statement assets and liabilities and their tax basis. Our current tax liability will be assessed based on the gross revenue apportioned to Texas. For the years ended December 31, 2014 and 2013, there were no material temporary differences.

On September 13, 2013, the U.S. Department of the Treasury and IRS issued the final and re-proposed tangible property regulations effective for tax years beginning January 1, 2014. The provisions of these regulations had no impact our financial statements.

Uncertain Tax Positions

We evaluate the uncertainty in tax positions taken or expected to be taken in the course of preparing our consolidated financial statements to determine whether the tax positions are more likely than not of being sustained by the applicable tax authority. Tax positions deemed not to meet the more likely than not threshold would be recorded as a tax benefit or expense in the current year. We believe that there are no uncertain tax positions and that no provision for income tax is required for these consolidated financial statements.

Earnings per Unit

Net income (loss) per unit is calculated under the two-class method of computing earnings per unit when participating or multiple classes of securities exist. Under this method, undistributed earnings or losses for a period are allocated based on the contractual rights of each security to share in those earnings as if all of the earnings for the period had been distributed.

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Basic net income (loss) per unit excludes dilution and is computed by dividing net income (loss) attributable to limited partner common units by the weighted average number of limited partner common units outstanding during the period. Paid-in kind distributions and valuation adjustments to maximum redemption value of the Series A convertible preferred units (which converted to common units on August 4, 2014) are excluded from income available to common units in the calculation of basic earnings per unit. Dilutive net income (loss) per unit reflects potential dilution from the potential issuance of limited partner common units. Dilutive net income (loss) per unit is calculated using the treasury stock method. It is computed by dividing net income (loss) attributable to limited partner common units by the weighted average number of limited partner common units outstanding during the period increased by the number of additional limited partner common units that would have been outstanding if the dilutive potential limited partner common units had been issued.

Investments in Joint Ventures

We now hold equity interests in three joint venture entities as a result of the TexStar Rich Gas System Transaction. We own a 50% or less equity interest in each of the three entities. The joint venture arrangements give equal management rights with no single investor having unilateral control. Each party sharing joint control must consent to the ventures' operating, investing and financing decisions. Therefore, because we do not have controlling financial interests, but do have significant influence, we use the equity method of accounting for investments in joint ventures. We recognize our share of the earnings and losses in the joint ventures pursuant to the terms of the applicable limited liability agreements governing such joint ventures, which provide for earnings and losses generally to be allocated based upon each member's respective ownership interest in the joint ventures. We record our proportionate share of the joint ventures' net income/loss as equity in income/losses of joint venture investments in the statements of operations. We evaluate investments in joint ventures for impairment when factors indicate that a decrease in the value of the investment has occurred that is not temporary. See Note 16.

Recent Accounting Pronouncements

Accounting standard-setting organizations frequently issue new or revised accounting rules. We review new pronouncements to determine their impact, if any, on our consolidated financial statements. We are evaluating the impact of each pronouncement on our consolidated financial statements.

In 2014, a comprehensive new revenue recognition standard that will supersede substantially all existing revenue recognition guidance under GAAP was issued. The standard's core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. We are required to adopt this standard beginning in the first quarter of 2017.

In 2014, a new discontinued operations standard was issued that will update existing discontinued operations guidance. The standard will raise the threshold for disposals to qualify as discontinued operations. We are required to adopt this standard beginning in the first quarter of 2015.

In 2014, a new going concern standard was issued that will update existing going concern guidance under GAAP. The standard's new guidance relates to defining management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern. Related disclosure in the notes to the consolidated financial statements will be required surrounding whether it is probable that the entity will not be able to meet its obligations as they become due within one year after the date that financial statements are issued. We are required to adopt this standard beginning in the first quarter of 2017.

2. LIQUIDITY CONSIDERATIONS

Our business exposes us to certain risks associated with the development of natural gas, crude oil and natural gas liquids which could have a material adverse effect on our cash flows, operations and liquidity, including, but not limited to:

- fluctuations in the volume of natural gas we gather, process, treat, compress and transport and the volume of NGLs we fractionate and transport;
- fluctuations in drilling and development activity in the geographic locations in which we operate;
- credit risk associated with all customers; and
- the level of production of, and the demand for, crude oil, natural gas and NGLs and the market prices of crude oil, natural gas and NGLs.

Beginning in the second half of 2014 and continuing through the issuance of our financial statements, commodity prices have experienced increased volatility. In particular, crude oil and NGL prices have decreased significantly. If we experience a material reduction in drilling in the geographic areas in which we operate, including the Eagle Ford Shale, or significant, prolonged pricing deterioration of the commodities we sell, our future cash flow may be materially adversely affected.

For the year ended December 31, 2014, the majority of our revenue was derived from fixed-fee contracts, which have limited direct exposure to commodity price levels since we are paid based on the volumes of natural gas that we gather, process, treat, compress and transport and the volumes of NGLs we fractionate and transport, rather than the value of the underlying natural gas or NGLs. A percentage of our contract portfolio contains minimum volume commitment arrangements. As a result of these contractual arrangements, the majority of our volumes associated with fixed-fee arrangements are dependent upon the level of drilling activity of producers.

After considering these uncertainties and in developing our annual budget for 2015, our forecast indicates a potential shortfall in the amount of consolidated EBITDA (as defined in our Credit Facility (as defined in Note 8)) to comply with the consolidated total leverage ratio of our financial covenants in our Credit Facility. As discussed in further detail in Note 8, we have the right (which cannot be exercised more than two times in any twelve month period or more than four times during the term of the facility) to cure such a Financial Covenant Default (as defined in Note 8) by having our Sponsors or Holdings purchase equity interests in or make capital contributions (an equity cure) to us resulting in, among other things, proceeds that, if added to consolidated EBITDA, as defined in the Credit Facility, would result in us satisfying the Financial Covenants (as defined in Note 8). Once such an equity cure is made, it is included in our consolidated EBITDA calculation in any rolling twelve month period that includes the quarter that was cured. Further, our Credit Facility does not place a dollar limit on the amount of an equity cure that can be contributed to comply with our Financial Covenants. Should there be an event of default under the Credit Facility, and such default is not cured, we would also experience a cross default under our Term Loan Agreement (defined in Note 8) and all of our debt would become due and payable to our lenders.

In response to the Partnership's expected need for additional liquidity, the controlling owners of Southcross Holdings GP LLC (the general partner of Holdings, which controls our General Partner) have committed to provide the necessary funding to support the Partnership for at least a reasonable period of time in an amount up to $25 million to ensure the Partnership has sufficient liquidity to comply with its applicable Financial Covenants, normal operating and growth capital requirements. Therefore, our financial statements have been presented as if the Partnership will continue as a going concern. See Note 8.

3. ACQUISITIONS

TexStar Rich Gas System Transaction. On August 4, 2014, contemporaneously with the closing of the Holdings Transaction, TexStar contributed to us certain gathering and processing assets (the "TexStar Rich Gas System"), through a contribution of TexStar's equity interest in the entities that own the TexStar Rich Gas System (the "Contribution") to us. In exchange for the Contribution, we paid $80 million in cash, assumed $100 million of debt (which was immediately repaid through our Term Loan Agreement (as defined in Note 8)) and issued 14,633,000 Class B Convertible Units (the "Class B Convertible Units"). The TexStar Rich Gas System consists of a cryogenic processing plant, located in Bee County, Texas, and joint venture ownership in natural gas gathering and residue pipelines across the core producing areas extending from Dimmit to Karnes Counties, Texas in the liquids-rich window of the Eagle Ford Shale region. These pipelines are operated under split-capacity arrangements within joint venture arrangements with Atlas Pipeline Partners, L.P.

The amount of the consideration paid over TexStar's net book value of the assets received and liabilities assumed of the TexStar Rich Gas System is recorded as a reduction to partners' capital as summarized as follows (in thousands):

Consideration paid[1]		**$ 404,414**
Current assets		$ 1,295
Property, plant and equipment, net		255,220
Investments in joint ventures[2]		152,050
Total assets contributed		408,565
Total liabilities assumed[3]		(102,776)
Net identifiable assets contributed		$ 305,789
Consideration paid in excess of net assets contributed		$ 98,625
Allocation of reduction to partners' capital:		
Common limited partner interest	$45,420	
Class B Convertible limited partner interest	27,925	
Subordinated limited partner interest	23,308	
General Partner interest	1,972	
Total reduction to partners' capital		$ 98,625

(1) This amount was calculated as follows: $80 million of cash plus 14,633,000 Class B Convertible Units at an issue price of $22.17, the closing price of the Partnership's common units on August 4, 2014.

(2) Significant assets acquired through the TexStar Rich Gas System Transaction include equity interests in three joint ventures. See Note 16.

(3) This amount includes $100 million of debt assumed.

Onyx Pipelines Acquisition. On March 6, 2014, our subsidiary, Southcross Nueces Pipelines LLC, acquired natural gas pipelines near Corpus Christi, Texas and contracts related to these pipelines from Onyx Midstream, LP and Onyx Pipeline Company (collectively, "Onyx") for $38.6 million in cash, net of certain adjustments as provided in the purchase agreement.

3. ACQUISITIONS (Continued)

The pipelines transport natural gas to two power plants in Nueces County, Texas under fixed-fee contracts that extend through 2029 and include an option to extend the agreements by an additional term of up to ten years. The contracts were renegotiated in connection with the acquisition; therefore, we consider these contracts to be assumed at fair market value.

The fair values of the property, plant and equipment are based upon assumptions related to expected future cash flows, discount rates and asset lives using currently available information. We utilized a mix of the cost, income and market approaches to determine the estimated fair values of such assets. The fair value measurements and models have been classified as non-recurring Level 3 measurements.

We performed our assessment of the fair value of the assets acquired and liabilities assumed, and the consideration given was considered equal to the fair value of net assets acquired. As a result, no goodwill was recorded. The assessment was finalized during the second quarter of 2014 and there were no changes to the preliminary balances previously recorded.

The fair value of the assets acquired and liabilities assumed related to the Onyx purchase price was as follows (in thousands):

Purchase Price—Cash	**$38,636**
Current assets	$ 730
Property, plant and equipment	39,413
Total assets acquired	40,143
Current liabilities assumed	(1,407)
Other liabilities assumed	(100)
Net identifiable assets acquired	$38,636

Unaudited Pro Forma Financial Information for Onyx Pipelines Acquisition. The following unaudited pro forma financial information for the year ended December 31, 2013 and the year ended December 31, 2014 assumes that the acquisition of pipelines from Onyx occurred on January 1, 2013 and includes adjustments for income from operations, including depreciation and amortization, as well as the effects of financing the transaction (in thousands, except unit information):

	Year Ended December 31,	
	2014	2013
Total revenue	$843,376	$639,104
Net loss	(31,400)	(18,306)
Net loss attributable to common unitholders	(20,211)	(9,934)
Net loss per common unit (basic and diluted)	(0.85)	(0.68)
Net loss attributable to subordinated unitholders	(8,373)	(9,678)
Net loss per subordinated unit (basic and diluted)	(0.69)	(0.79)

3. ACQUISITIONS (Continued)

The unaudited pro forma information is not necessarily indicative of what our statements of operations would have been if the transaction had occurred on that date, or what the financial position or results from operations will be for any future periods. For the year ended December 31, 2014, the Onyx pipelines business contributed $4.2 million in revenues and $1.3 million in net income to our statements of operations.

Texoz Acquisition. On November 21, 2014, we completed the acquisition of a natural gas gathering system in McMullen County, Texas (the “Texoz System”) from LT Gathering, LLC for $5.4 million in cash, net of certain adjustments as provided in the purchase agreement (the “Texoz Acquisition”). The Texoz System consists of eight miles of gathering pipelines within two miles of our existing rich gas pipeline network and services customers under acreage dedication contracts. Due to the immaterial amount of this transaction, no pro-forma financial information was disclosed in this report.

4. TRANSACTION-RELATED COSTS

During the year ended December 31, 2014, we recognized $9.9 million of transaction-related costs in connection with the Onyx acquisition, the Holdings Transaction, the TexStar Rich Gas System Transaction and the Texoz Acquisition, which are recorded in operations and maintenance and general and administrative expenses. For the year ended December 31, 2014, these costs include (a) $7.2 million related to the accelerated vesting of the LTIP awards (as defined in Note 5) due to the change in control as further discussed in Note 14, (b) $1.7 million of advisory, audit and legal fees, (c) $0.6 million of charges associated with employees’ severance, (d) $0.3 million related to professional fees associated with the Onyx acquisition and the Texoz Acquisition and (e) $0.1 million related to the accelerated vesting of the Southcross Energy LLC equity equivalent units due to the change in control as further discussed in Note 14. We expect to incur additional costs relating to integration and other activities throughout 2015.

5. EARNINGS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS

Earnings Per Unit of the Partnership

The following is a reconciliation of net loss attributable to limited partners and the limited partner units used in the basic and diluted earnings per unit calculations for the years ended December 31, 2014, 2013 and 2012 (in thousands, except per unit data):

	Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012
Net loss	$(31,322)	$(15,970)	$(4,488)
Series A Preferred Unit fair value adjustment(1)	(4,596)	(37)	—
Series A Preferred Unit in-kind distribution	(534)	(1,633)	—
General partner Unit in-kind distribution	(207)	—	—
Net loss from January 1, 2012 through November 6, 2012	—	—	260
Net loss attributable to partners	$(36,659)	$(17,640)	$(4,228)
General partner's interest(2)	(693)	(319)	—
Limited partners' Class B Convertible interest(2)	(7,436)	—	—
Limited partners' interest(2)			
Common	(20,175)	(8,683)	(2,072)
Subordinated	(8,355)	(8,638)	(2,071)

(1) The valuation adjustment to maximum redemption value of the Series A Preferred Unit in-kind distribution increased the net loss attributable to partners for the years ended December 31, 2014 and 2013 in the calculation of earnings per unit (See Note 11).

(2) General Partner's and limited partners' interests are calculated based on the allocation of net losses for the period, net of the allocation of Series A Preferred Unit in-kind distributions, Series A Preferred Unit fair value adjustments and General Partner unit in-kind distributions. The Class B Convertible Unit interest is calculated based on the allocation of only net losses for the period.

Common Units	Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012
Interest in net loss	$ (20,175)	$ (8,683)	$ (2,072)
Effect of dilutive units—numerator(1)	—	—	—
Dilutive interest in net loss	$ (20,175)	$ (8,683)	$ (2,072)
Weighted-average units—basic	21,641,635	12,224,997	12,213,713
Effect of dilutive units—denominator(1)	—	—	—
Weighted-average units—dilutive	21,641,635	12,224,997	12,213,713
Basic and diluted net loss per common unit	$ (0.93)	$ (0.71)	$ (0.17)

5. EARNINGS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS (Continued)

Subordinated Units	Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012
Interest in net loss	$ (8,355)	$ (8,638)	$ (2,071)
Effect of dilutive units—numerator[(1)]	—	—	—
Dilutive interest in net loss	$ (8,355)	$ (8,638)	$ (2,071)
Weighted-average units—basic	12,213,713	12,213,713	12,213,713
Effect of dilutive units—denominator[(1)]	—	—	—
Weighted-average units—dilutive	12,213,713	12,213,713	12,213,713
Basic and diluted net loss per subordinated unit	$ (0.68)	$ (0.71)	$ (0.17)

(1) Because we had a net loss for all periods for common units and the subordinated units, the effect of the dilutive units would be anti-dilutive to the per unit calculation. Therefore, the weighted average units outstanding are the same for basic and dilutive net loss per unit for those periods. The weighted average units that were not included in the computation of diluted per unit amounts were 184,417 and 10,092 and unvested awards granted under our LTIP for the year ended December 31, 2014 and 2013, respectively, and 1,213,257 Series A Preferred Units for the year ended December 31, 2013.

Our calculation of the number of weighted-average units outstanding includes the common units that have been awarded to our directors that are deferred under our Non-Employee Director Deferred Compensation Plan.

All of our Series A Preferred Units were converted into common units on August 4, 2014 (See Note 11). Prior to conversion, our Series A Preferred Units were considered participating securities for purposes of the basic earnings per unit calculation during periods in which they received cash distributions. We were required to pay in-kind distributions to the Series A Preferred Units for the first four full quarters beginning the second quarter of 2013, and continued to pay these distributions until the Series A Preferred Units were converted into common units. Because the Series A Preferred Units received in-kind distributions, they have been excluded from the basic earnings per unit calculation for the year ended December 31, 2014.

Distributions

Our agreement of limited partnership, which was amended and restated on August 4, 2014 in order to establish the Class B Convertible Units (as amended and restated, the "Partnership Agreement"), requires that within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our General Partner. We intend to make a minimum quarterly distribution to the holders of our common units and subordinated units of $0.40 per unit, or $1.60 on an annualized basis, to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our General Partner. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Beginning with the third quarter of 2014, until such time that we have a distributable cash flow divided by cash distributions ratio ("Distributable Cash Flow Ratio") of at least 1.0, Holdings, the holder of all of our subordinated units, has waived the right to receive distributions on any subordinated units that would cause the Distributable Cash Flow Ratio to be less than 1.0. With respect to the fourth quarter of 2014, Holdings also waived the requirement that any distribution owed to it for that quarter be paid within 45 days of the end of the quarter, provided that the distribution is paid before or in conjunction with the filing of this Form 10-K.

5. EARNINGS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS (Continued)

Our General Partner is currently entitled to 2.0% of all distributions that we make prior to our liquidation. Our General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our General Partner's initial 2.0% interest in our distributions will be reduced if we issue additional limited partner units in the future and our General Partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

Our General Partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus in excess of $0.46 per unit per quarter. The maximum distribution of 50% includes distributions paid to our General Partner on its 2.0% general partner interest and assumes that our General Partner maintains its general partner interest at 2.0%. The maximum distribution of 50% does not include any distributions that our General Partner may receive on any limited partner units that it owns.

Cash Distributions

The following table represents our distribution declared for the quarter ended December 31, 2014 and distributions paid for the previous periods (in thousands, except per unit data):

			Distributions			
			Limited Partners			
Payment Date	Attributable to the Quarter Ended	Per Unit Distribution	Common	Subordinated	General Partner	Total
2014						
February 13, 2015	December 31, 2014	$0.40(1)	$9,520	$3,432(3)	$416	$13,368
November 14, 2014	September 30, 2014	0.40(1)	9,520	—	413	9,933
August 14, 2014	June 30, 2014	0.40	9,399	4,886	290	14,575
May 15, 2014	March 31, 2014	0.40	8,586	4,886	290	13,762
2013						
February 14, 2014	December 31, 2013	0.40	8,581	4,885	289	13,755
November 14, 2013	September 30, 2013	0.40	4,888	4,885	214	9,987
August 14, 2013	June 30, 2013	0.40	4,890	4,886	210	9,986
May 15, 2013	March 31, 2013	0.40	4,888	4,886	199	9,973
2012						
February 14, 2013	December 31, 2012	0.24(2)	2,931	2,931	120	5,982

(1) The common unit distribution in the table above includes the distribution payment to the Series A Preferred unitholders for their Series A Preferred Units converted into common units or to the units that vested as part of our LTIP (as defined below) as a result of the Holdings Transaction (See Notes 1, 11 and 14).

(2) Per unit distribution of $0.24 corresponds to the minimum quarterly distribution of $0.40 per unit, or $1.60 on an annualized basis, pro-rated for the portion of the quarter following the closing of our IPO on November 7, 2012.

(3) Holdings waived the requirement that any distribution owed to it for the fourth quarter be paid within 45 days of the end of the quarter. We expect to pay a distribution of $0.28 on 12,213,713 of our Subordinated Units in conjunction with the filing of this Form 10-K.

5. EARNINGS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS (Continued)

In accordance with our 2012 long-term incentive plan ("LTIP"), we paid the distribution equivalent rights to holders of LTIP units that vested during year ended December 31, 2014 (See Note 14). On November 14, 2013, we paid an aggregate distribution of $63.8 thousand to the holders of the vested phantom units.

Paid In-Kind Distributions

During the second quarter of 2013, we raised $40.0 million of equity through issuances of 1,715,000 Series A Preferred Units and an additional General Partner contribution to satisfy the requirements of our Previous Credit Facility (as defined in Note 8) (See Notes 8 and 11). Under the terms of our Partnership Agreement, we were required to pay the holders of our Series A Preferred Units quarterly distributions of in-kind Series A Preferred Units for the first four full quarters following the issuance of the units and continuing thereafter until the board of directors of our General Partner determined to begin paying quarterly distributions in cash. In-kind distributions were in the form of Series A Preferred Units at a rate of $0.40 per outstanding Series A Preferred Unit per quarter (or 7% per year of the per unit purchase price). Cash distributions were required to equal the greater of $0.40 per unit per quarter or the quarterly distribution paid with respect to each common unit. In accordance with the Partnership Agreement, our General Partner received a corresponding distribution of in-kind general partner units to maintain its 2.0% interest in us. In connection with the Holdings Transaction (see Notes 1 and 3), all holders of the Series A Preferred Units elected to convert their Series A Preferred Units into 2,015,638 common units based on a 110% exchange ratio.

The following table represents the paid in-kind ("PIK") distribution from the date of our IPO through August 4, 2014, the date on which all outstanding Series A Preferred Units were converted to common units (in thousands, except per unit and in-kind distribution units):

Payment Date	Attributable to the Quarter Ended(1)	Per Unit Distribution	In-Kind Series A Preferred Unit Distributions to Series A Preferred Holders	In-Kind Series A Preferred Distributions Fair Value(2)	In-Kind Unit Distribution to General Partner	In-Kind General Partner Distribution Value(2)
2014						
May 15, 2014	March 31, 2014	$0.40	31,513	$534	643	$11
2013						
February 14, 2014	December 31, 2013	$0.40	30,971	$558	632	$11
November 14, 2013	September 30, 2013	0.40	30,439	511	621	10
August 14, 2013	June 30, 2013	0.35(3)	22,276	512	454	10
August 14, 2013	June 30, 2013	0.20(4)	2,199	51	45	1

(1) As a result of the conversion, the Series A Preferred Unit holders (and the corresponding General Partner units) did not receive a PIK distribution for the quarters ended June 30, 2014 or September 30, 2014, but received a cash distribution on the converted common units.

(2) The fair value was calculated as required, based on the common unit price at the quarter end date for the period attributable to the distribution, multiplied by the number of units distributed.

(3) Per unit distribution of $0.35 corresponds to the minimum quarterly distribution of $0.40 per unit, or $1.60 on an annualized basis, pro-rated for the portion of the quarter following the issuance of 1,466,325 Series A Preferred Units and 29,925 general partner units on April 12, 2013.

5. EARNINGS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS (Continued)

(4) Per unit distribution of \$0.20 corresponds to the minimum quarterly distribution of \$0.40 per unit, or \$1.60 on an annualized basis, pro-rated for the portion of the quarter following the issuance of 248,675 Series A Preferred Units and 5,075 general partner units on May 15, 2013.

Class B Convertible Units. In connection with the Contribution, on August 4, 2014, we established our Class B Convertible Units. The Class B Convertible Units consist of 14,633,000 of such units plus any additional Class B Convertible Units issued in-kind as a distribution ("Class B PIK Units"). The Class B Convertible Units are not participating securities for purposes of the earnings per unit calculation. Commencing with the quarter ended September 30, 2014 and until converted, as long as certain requirements are met, the holders of the Class B Convertible Units will receive quarterly distributions in an amount equal to \$0.3257 per unit. These distributions will be paid quarterly in Class B PIK Units within 45 days after the end of each quarter. Our General Partner was entitled, and has exercised its right, to retain its 2.0% general partner interest in us in connection with the original issuance of Class B Convertible Units. In connection with future distributions of Class B PIK Units, the General Partner is entitled to a corresponding distribution to maintain its 2.0% general partner interest in us. The Class B Convertible Units have the same rights, preferences and privileges, and are subject to the same duties and obligations, as our common units, with certain exceptions. See Note 12.

The following table represents the PIK distribution earned on the Class B Convertible Units for periods after August 4, 2014 and ended December 31, 2014 (in thousands, except per unit and in-kind distribution units):

Payment Date	Attributable to the Quarter Ended	Per Unit Distribution	In-Kind Class B Convertible Unit Distributions to Class B Convertible Holders	In-Kind Class B Convertible Distributions Value[(1)]	In-Kind Unit Distribution to General Partner	In-Kind General Partner Distribution Value[(1)]
2014						
February 13, 2015	December 31, 2014	\$0.3257	260,558	\$4,143	5,318	\$ 85
November 14, 2014	September 30, 2014	\$0.3257	256,078	\$5,467	5,226	\$112

(1) The fair value was calculated as required, based on the common unit price at the quarter end date for the period attributable to the distribution, multiplied by the number of units distributed.

Earnings Per Common Unit of Southcross Energy LLC

A reconciliation of basic and diluted earnings per unit related to the Southcross Energy LLC common units is included in our consolidated statements of operations.

Southcross Energy LLC calculated earnings per common unit by first deducting the amount of cumulative returns on both the Redeemable Preferred and Preferred units from net income (loss), and dividing this amount by the weighted average number of vested common units (including both the vested Class A common units and Class B units). For periods presented in which Southcross Energy LLC units were outstanding, no unvested common units were included in the computation of the diluted per unit amount because all would have been antidilutive to the net loss per common unit holder. The amount of unvested common units that were not included in the computation of diluted per unit amounts were 143,220 units for the period ended November 6, 2012.

6. FINANCIAL INSTRUMENTS

Fair Value Measurements

We apply recurring fair value measurements to our financial assets and liabilities. In estimating fair value, we generally use a market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. The fair value measurement inputs we use vary from readily observable inputs that represent market data obtained from independent sources to unobservable inputs that reflect our own market assumptions that cannot be validated through external pricing sources. Based on the observability of the inputs used in the valuation techniques, the financial assets and liabilities carried at fair value in the financial statements are classified as follows:

- Level 1—Represents unadjusted quoted market prices in active markets for identical assets or liabilities that are accessible at the measurement date. This category primarily includes our cash and cash equivalents, accounts receivable and accounts payable.
- Level 2—Represents quoted market prices for similar assets or liabilities in active markets, quoted market prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. This category primarily includes variable rate debt, over-the-counter swap contracts based upon natural gas price indices and interest rate derivative transactions.
- Level 3—Represents derivative instruments whose fair value is estimated based on internally developed models and methodologies utilizing significant inputs that are generally less readily observable from market sources. We do not have financial assets and liabilities classified as Level 3.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy must be determined based on the lowest level input that is significant to the fair value measurement. An assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and consideration of factors specific to the asset or liability.

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable represent fair values based on the short-term nature of these instruments. The fair value of the debt funded through our credit facilities approximates its carrying amount due primarily to the variable nature of the interest rate of the instrument and is considered a Level 2 fair value measurement.

Derivative Financial Instruments

Interest Rate Derivative Transactions

We manage a portion of our interest rate risk through interest rate swaps. In March 2012, we terminated an interest rate cap contract and entered into an interest rate swap contract with Wells Fargo, N.A. The interest rate swap had a notional value of $150.0 million, and a maturity date of June 30, 2014. We received a floating rate based upon one-month LIBOR and paid a fixed rate under the interest rate swap of 0.54%.

The interest rate swap was designated as a cash flow hedge for accounting purposes at inception of the contract and, thus, to the extent the cash flow hedge was effective, unrealized gains and losses were recorded to accumulated other comprehensive income/loss and recognized in interest expense as the underlying hedged transactions (interest payments) were recorded. Any hedge ineffectiveness was recognized in interest expense immediately. We did not have any hedge ineffectiveness during the years ended December 31, 2014 and 2013.

In February 2014, we discontinued cash flow hedge accounting on a prospective basis as a result of the $148.5 million repayment of borrowings under our Previous Credit Facility (as defined in Note 8). The fair value

6. FINANCIAL INSTRUMENTS (Continued)

of the interest rate swap recorded in accumulated other comprehensive loss at the cash flow hedge de-designation date was $0.1 million. This balance was reclassified into interest expense as interest on the hedged debt was recorded. No ineffectiveness was recorded as a result of the cash flow hedge de-designation. Changes in the fair value of the interest rate swap for the remainder of the contract term were recognized in interest expense.

We enter into interest rate swap contracts whereby we receive a floating rate and pay a fixed rate to reduce the risk associated with the variability of interest rates for our term loan borrowings. These interest rate swaps are not designated as cash flow hedges and as a result, changes in the fair value of the interest rate swaps are recognized in interest expense immediately.

We have elected to present our interest rate swaps net on the balance sheets. There was no effect of offsetting on the balance sheets for the years ended December 31, 2014 and 2013. Our interest rate swap position was as follows (in thousands):

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Value December 31, 2014
$ 140,000	0.327%	June 30, 2014	June 30, 2015	$ (97)
50,000	1.198%	September 30, 2014	June 30, 2016	(59)
50,000	1.196%	September 30, 2014	June 30, 2016	(58)
				$(214)

In December 2014, we entered into an interest rate cap contract for $20.0 million notional value, effective December 31, 2014, with a maturity date of December 31, 2016. The contract effectively caps our LIBOR-based interest rate on that portion of debt at 1.5%. We did not designate the interest rate cap as a hedging instrument for accounting purposes, and as a result, changes in the fair value are recognized in interest expense immediately.

The fair value of our interest rate derivative transactions is determined based on a discounted cash flow method using contractual terms of the transactions. The floating coupon rate is based on observable rates consistent with the frequency of the interest cash flows.

The fair values of our interest rate derivative transactions were as follows (in thousands):

	Significant Other Observable Inputs (Level 2)	
	Fair Value Measurement as of	
	December 31, 2014	December 31, 2013
Current interest rate derivative assets	$ 27	$ —
Non-current interest rate derivative assets	$ 27	$ —
Current interest rate derivative (liabilities)	$(175)	$(263)
Non-current interest rate derivative (liabilities)	$ (39)	$ —
Total interest rate derivatives	$(160)	$(263)

6. FINANCIAL INSTRUMENTS (Continued)

The effect of the interest rate swap designated as a cash flow hedge in our statements of changes in partners' capital and members' equity and comprehensive loss was as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Change in value recognized in other comprehensive loss—effective portion	$ (11)	$(148)	$(745)
Loss reclassified from accumulated other comprehensive loss to interest expense	$221	$ 415	$ 268

There were no amounts of gains or losses reclassified into earnings as a result of the discontinuance of cash flow hedge accounting due to the lack of probability of the forecasted transaction occurring.

The realized and unrealized amounts recognized in interest expense associated with derivatives that are not designated as hedging instruments were as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Unrealized loss on interest rate derivatives	$160	$ —	$141
Realized loss on interest rate derivatives	$316	$108	$ 82

Commodity Swaps

In our normal course of business, we periodically enter into month-ahead swap contracts to hedge our exposure to certain intra-month natural gas index pricing risk. The total volume of outstanding month-ahead swap contracts as of December 31, 2014 and 2013 was 12,000 MMBtu per day and 33,722 MMBtu per day, respectively. We had no outstanding month-ahead swap contracts as of December 31, 2012. We define these contracts as Level 2 because the index price associated with such contracts is observable and tied to a similarly quoted first-of-the-month natural gas index price.

We have elected to present our commodity swaps net on the balance sheets. We did not have any cash collateral received or paid on our commodity swaps as of December 31, 2014 or 2013. The effect of offsetting on our balance sheets were as follows (in thousands):

	December 31, 2014		December 31, 2013	
	Other Current Assets	Other Current Liabilities	Other Current Assets	Other Current Liabilities
Gross amounts of recognized assets (liabilities)	$112	$—	$140	$(20)
Gross amounts offset on the balance sheets	—	—	(20)	20
Net amount	112	—	120	—

6. FINANCIAL INSTRUMENTS (Continued)

The realized and unrealized gain/loss on these derivatives, recognized in revenues in our statements of operations, were as follows (in thousands):

	Year ended December 31,		
	2014	2013	2012
Realized (loss) gain on commodity swap derivatives	$347	$(659)	$(12)
Unrealized (loss) gain on commodity swap derivatives	(8)	120	—

7. LONG-LIVED ASSETS

Property, Plant and Equipment

Property, plant and equipment consist of the following (in thousands):

	Estimated Useful Life	As of December 31, 2014	As of December 31, 2013
Pipelines	30	$ 468,843	$344,721
Gas processing, treating and other plants	15	482,418	254,133
Compressors	7	37,865	20,030
Rights of way and easements	15	29,803	20,729
Furniture, fixtures and equipment	5	3,671	3,347
Capital lease vehicles	3-5	2,077	1,396
Total property, plant and equipment		1,024,676	644,356
Accumulated depreciation and amortization		(131,615)	(79,908)
Total		893,061	564,448
Construction in progress		50,051	6,039
Land and other		25,698	5,308
Property, plant and equipment, net		$ 968,810	$575,795

Depreciation is provided using the straight-line method based on the estimated useful life of each asset. Depreciation expense for the years ended December 31, 2014, 2013 and 2012 was $42.2 million, $33.5 million and $19.0 million, respectively.

In January 2013, we shut down our Gregory facility to perform extensive turnaround maintenance activities and to connect additional equipment to enhance NGL recoveries. As the turnaround maintenance was nearing completion, we experienced a fire at this facility. In connection with the fire, as of December 31, 2014, we spent $5.5 million to return the facility to service and filed an insurance claim related to these costs. We recovered $1.0 million in 2013 and $3.9 million in 2014 from insurance proceeds for this loss, less a $0.3 million deductible, under our insurance policies. We received the remaining approximately $0.6 million outstanding at December 31, 2014 in January 2015.

Intangible Assets

Intangible assets of $1.5 million and $1.6 million as of December 31, 2014 and 2013, respectively, represent the unamortized value assigned to long-term supply and gathering contracts acquired in 2011. These intangible assets are amortized on a straight-line basis over the 30-year expected useful lives of the contracts through 2041. Amortization expense over the next five years related to intangible assets is not significant.

8. LONG-TERM DEBT

Our outstanding debt and related information at December 31, 2014 and December 31, 2013 are as follows (in thousands):

	As of December 31,	
	2014	2013
Credit facility due 2019	$ 30,000	$267,300
Term loans (including OID of $2.1 million) due 2021	445,629	—
Total long-term debt (including current portion)	$475,629	$267,300
Current portion of long-term debt	$ (4,500)	$ —
Total long-term debt	$471,129	$267,300
Outstanding letters of credit	$ 30,130	$ 31,260
Remaining unused borrowings	$139,870	$ 69

	Year Ended December 31,	
	2014	2013
Weighted average interest rate	4.6%	4.4%
Average outstanding borrowings	$308,670	$243,920
Maximum borrowings	$491,875	$267,300

	Total	2015	2016	2017	2018	2019	Thereafter
Maturity							
Long-term debt	$475,629	$4,500	$4,500	$4,500	$4,500	$34,500	$423,129

Previous Credit Facility

In November 2012, we entered into a five-year $350.0 million revolving credit facility (as amended, the "Previous Credit Facility"). Borrowings under the Previous Credit Facility were set to mature in November 2017. We utilized the Previous Credit Facility for working capital requirements and capital expenditures, the purchase of assets, the payment of distributions and other general purposes. During 2013 and the first quarter of 2014, we entered into a total of four amendments to the Previous Credit Facility, primarily as a result of some operational challenges including the start up of our Bonnie View fractionator and the January 2013 fire at our Gregory facility. These impacted our operating results adversely and resulted in the need for the various amendments to our Previous Credit Facility. In connection with these amendments, our availability was reduced from $350.0 million to the sum of $250.0 million, plus any amounts placed on deposit in a collateral account of our General Partner and letters of credit outstanding. This availability was increased to $350.0 million in connection with the fourth amendment in March 2014. In connection with the closing of the TexStar Rich Gas System Transaction, we refinanced our Previous Credit Facility and entered into the Senior Credit Facilities (as defined below).

Senior Credit Facilities

On August 4, 2014, in connection with the consummation of the Contribution, we entered into (a) a Third Amended and Restated Revolving Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, JPMorgan Chase Bank, N.A., as Documentation Agent, and a syndicate of lenders (the "Third A&R Revolving Credit Agreement") and (b) a

8. LONG-TERM DEBT (Continued)

Term Loan Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, and a syndicate of lenders (the “Term Loan Agreement” and, together with the Third A&R Revolving Credit Agreement, the “Senior Credit Facilities”). The initial borrowings and extensions of credit under the Term Loan Agreement were used to finance the TexStar Rich Gas System Transaction (including the immediate repayment of the $100 million of debt assumed in the transaction), the repayment of certain of our existing debt and the payment of fees and expenses in connection with the new debt arrangements and ongoing working capital and other general partnership purposes. No amounts were initially drawn on the Third A&R Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under the Senior Credit Facilities, with the security interest of the facilities ranking pari passu. See Note 2.

Third A&R Revolving Credit Agreement

The Third A&R Revolving Credit Agreement is a five-year $200 million revolving credit facility (the “Credit Facility”). Borrowings under our Credit Facility bear interest at the London Interbank Offered Rate (“LIBOR”) plus an applicable margin or a base rate as defined in the respective credit agreement. Pursuant to the Third A&R Revolving Credit Agreement, among other things:

(a) the letters of credit sublimit increased to $75.0 million;

(b) we have the right to increase the total commitments under the Credit Facility by obtaining additional commitments from other lenders, as long as our senior secured leverage ratio is less than or equal to 4.50 to 1.00 before and after giving effect to such increase, subject to certain other conditions;

(c) the definition of “Change of Control” was amended to permit the combination transaction with TexStar and to reflect the Sponsors’ control of the General Partner;

(d) our maximum consolidated total leverage ratio is set at (i) 5.75 to 1.00 as of the last day of the fiscal quarter ending December 31, 2014, (ii) 5.50 to 1.00 as of the last day of the fiscal quarter ending March 31, 2015, (iii) 5.25 to 1.00 as of the last day of the fiscal quarter ending June 30, 2015 and (iv) 5.00 to 1.00 as of the last day of each fiscal quarter thereafter, in each case, without any step-ups in connection with acquisitions;

(e) we have the right, exercisable on or before the date that our annual audited financial statements are due for the 2014 fiscal year, to comply with the consolidated total leverage ratio, consolidated senior secured leverage ratio and the consolidated interest coverage ratio covenants (the “Financial Covenants”) by applying certain specified quarterly base periods pertaining to the TexStar Rich Gas System;

(f) if we fail to comply with the Financial Covenants (a “Financial Covenant Default”), we have the right (which cannot be exercised more than two times in any twelve month period or more than four times during the term of the facility) to cure such Financial Covenant Default by having our Sponsors purchase equity interests in or make capital contributions to us resulting in, among other things, proceeds that, if added to consolidated EBITDA, as defined in the Third A&R Revolving Credit Agreement, would result in us satisfying the Financial Covenants;

(g) certain definitions are amended to take into account the TexStar Rich Gas System; and

(h) the negative covenants are amended to permit the entry into, and indebtedness under, the Term Loan Agreement.

8. LONG-TERM DEBT (Continued)

Term Loan Agreement

The Term Loan Agreement is a seven-year $450 million senior secured term loan facility (the “Term Loan”). On August 4, 2014, the lenders funded the full amount of the facility. Borrowings under our Term Loan Agreement bear interest at LIBOR plus 4.25% or a base rate as defined in the respective credit agreement with a LIBOR floor of 1.00%. Under the Term Loan Agreement, among other things:

(a) subject to certain requirements, including the absence of a default and pro forma compliance under the Third A&R Revolving Credit Agreement and pro forma compliance with a senior secured leverage ratio less than or equal to 4.50 to 1.00 before and after giving effect to such increase, we may from time to time request incremental term loan commitments subject to certain other conditions;

(b) we may seek commitments from third party lenders in connection with any incremental term loan commitment requests, subject to certain consent rights given to the administrative agent;

(c) the guarantors and the collateral are the same as provided for the benefits of lenders in the Third A&R Revolving Credit Agreement;

(d) subject to certain conditions, we may request that the lenders extend the seven-year maturity of all or a portion of the outstanding loans under the facility;

(e) the facility will amortize in equal quarterly installments of $1.125 million in an aggregate annual amount equal to 1% of the original principal amount of the initial loan, with the remainder due on the maturity date;

(f) there are customary mandatory prepayment provisions and, subject to certain conditions, permissive prepayment provisions; provided, that if certain repricing transactions occur, we must pay a call premium equal to 1% of the principal amount of the loans subject to the repricing transactions; and

(g) there are customary representations and warranties, affirmative covenants, negative covenants and provisions governing an event of default (including acceleration of payment in connection with material indebtedness, including the Third A&R Revolving Credit Agreement).

See Note 2 for further detail.

9. COMMITMENTS AND CONTINGENT LIABILITIES

Legal Matters

On March 5, 2013, one of our subsidiaries, Southcross Marketing Company Ltd., filed suit in a District Court of Dallas County against Formosa Hydrocarbons Company, Inc. (“Formosa”). The lawsuit sought recoveries of losses that we believe our subsidiary experienced as a result of the failure of Formosa to perform certain obligations under the gas processing and sales contract between the parties. Formosa filed a response generally denying our claims and, later, Formosa filed a counterclaim against our subsidiary claiming our affiliate breached the gas processing and sales contract and a related agreement between the parties for the supply by Formosa of residue gas to a third party on behalf of our subsidiary. After a bench trial held in January 2015, on February 5, 2015, the judge ruled that Formosa breached certain of its obligations under the

9. COMMITMENTS AND CONTINGENT LIABILITIES (Continued)

gas processing and sales contract and that our subsidiary breached an obligation under each of the gas processing and sales contract and the related residue gas agreement. The amount of damages awarded to our subsidiary was in excess of the damages awarded to Formosa. However, the ultimate amount to be recovered by our subsidiary will not be finalized until the judge awards attorneys' fees, if any. Until that issue is resolved, a judgment will not be entered and, as a result, we do not know the ultimate financial outcome of the lawsuit. Regardless of the attorneys' fee issue, the judgment is not expected to have a material impact on our results of operations, cash flows or financial condition. We currently expect a final judgment to be entered in the second quarter of 2015, which may be appealed.

From time to time, we are party to certain legal or administrative proceedings that arise in the ordinary course and are incidental to our business. For example, during periods when we are expanding our operations through the development of new pipelines or the construction of new plants, we may become involved in disputes with landowners that are in close proximity to our activities. While we are currently involved in several such proceedings and disputes, our management believes that none of such proceedings or disputes will have a material adverse effect on our results of operations, cash flows or financial condition. However, future events or circumstances, currently unknown to management, will determine whether the resolution of any litigation or claims ultimately will have a material effect on our results of operations, cash flows or financial condition in any future reporting periods.

Regulatory Compliance

In the ordinary course of our business, we are subject to various laws and regulations. In the opinion of our management, compliance with current laws and regulations will not have a material effect on our results of operations, cash flows or financial condition.

Leases

Capital Leases

We have auto leases classified as capital leases. The termination dates of the lease agreements vary from 2014 to 2018. We recorded amortization expense related to the capital leases of $0.6 million and $0.5 million for the year ended December 31, 2014 and 2013, respectively. Capital leases entered into during the year ended December 31, 2014 and 2013 were $0.7 million and $1.4 million, respectively. The capital lease obligation amounts included on the balance sheets were as follows (in thousands):

	December 31, 2014	December 31, 2013
Other current liabilities	$ 455	$481
Other non-current liabilities	578	427
Total	$1,033	$908

Operating Leases

We maintain operating leases in the ordinary course of our business activities. These leases include those for office and other operating facilities and equipment. The termination dates of the lease agreements vary from 2014 to 2025. Expenses associated with operating leases, recorded in operations and maintenance expenses and general and administrative expenses in our statements of operations, were $1.5 million, $1.5 million and $2.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

9. COMMITMENTS AND CONTINGENT LIABILITIES (Continued)

Future Minimum Lease Payments

Future minimum annual rental commitments under our capital and operating leases at December 31, 2014 were as follows (in thousands):

Years Ending December 31,	Capital Leases	Operating Leases
2015	$ 468	$ 1,170
2016	283	1,156
2017	212	1,122
2018	95	1,055
2019	3	1,080
Thereafter	—	$ 5,775
Total future payments	1,061	$11,358
Less: Imputed interest	$ (35)	
Future lease payments	$1,026	

Purchase Commitments

At December 31, 2014, we had commitments of approximately $17.9 million for purchases of material and equipment related to our capital projects, primarily the construction of the Webb Pipeline. We have other planned capital projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures.

10. TRANSACTIONS WITH RELATED PARTIES

Charlesbank, EIG & Tailwater (our Sponsors)

For the year ended December 31, 2012, Southcross Energy LLC incurred management fees of $0.5 million for services received and incurred associated expenses of $68,000 under the Charlesbank Agreement (as defined below). Service fees and expenses under the Charlesbank Agreement were recognized in general and administrative expenses in our consolidated statements of operations. Subsequent to our IPO, we did not receive any further services under this agreement, as the Charlesbank Agreement terminated with our IPO. Therefore, no payments for services provided after that date were made under the Charlesbank Agreement.

10. TRANSACTIONS WITH RELATED PARTIES (Continued)

Effective August 4, 2014, in connection with the Contribution and as a result of the Holdings Transaction, the board of directors of our General Partner includes one director affiliated with Charlesbank, one director affiliated with EIG, one director affiliated with Tailwater and three outside directors. The seventh member of the board of directors of our General Partner and its chairman, David W. Biegler, was selected by a majority of the other directors. Mr. Biegler will serve as the chairman from August 2014 for two years or until his earlier death or resignation. Our non-employee directors are reimbursed for certain expenses incurred for their services to us. The director services fees and expenses are included in general and administrative expenses in our statements of operations. We incurred fees and expenses related to the services from our affiliated directors as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Charlesbank	$340	$463	$—
EIG	20	—	—
Tailwater	20	—	—
Total fees and expenses paid for director services to affiliated entities	$380	$463	$—

Southcross Energy LLC and Southcross Energy Partners GP, LLC

Prior to our IPO in 2012, Charlesbank provided certain management services to Southcross Energy LLC pursuant to a management services agreement (the "Charlesbank Agreement") which specified an annual management fee of $0.6 million. Subsequent to our IPO, we did not receive any further services under this agreement, as the Charlesbank Agreement terminated with our IPO. As such, our General Partner no longer receives a management fee or other compensation for its management of us. However, our General Partner and its affiliates are entitled to reimbursements for all expenses incurred on our behalf, including, among other items, compensation expense for all employees required to manage and operate our business. We incurred expenses related to these reimbursements as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Reimbursements included in general and administrative expenses	$10,944	$ 9,364	$—
Reimbursements included in operations and maintenance expenses	16,093	13,264	—
Total reimbursements to our General Partner and its affiliates	$27,037	$22,628	$—

Compensation expense for services incurred by us on behalf of Southcross Energy LLC was billed to Southcross Energy LLC. For the year ended December 31, 2014, compensation expense, which was not incurred on our behalf, of $0.9 million was billed to Southcross Energy LLC, $0.5 million of which is included in accounts receivable as of December 31, 2014.

In December 2014, Southcross Energy LLC, on behalf of us, paid the settlement of the $1.2 million liability in connection with the accelerated vesting of the 15,000 outstanding equity equivalent units held by management due to the change in control provision triggered by the Holdings Transaction. See Note 14.

10. TRANSACTIONS WITH RELATED PARTIES (Continued)

We also provide management, administrative, operational and workforce related services to affiliated entities including Holdings, which owns 100% of our General Partner, and an affiliate that is jointly owned by EIG and Tailwater, two of our Sponsors. The expenses associated with these services, which are shared with these entities, are recorded in general and administrative expense in our statement of operations and are allocated in a manner approved by the board of directors and conflicts committee. During the year ended December 31, 2014, we allocated $1.0 million to Holdings, and $0.1 million to an affiliate of two of our Sponsors.

In 2014, we paid approximately $2.8 million to Black Creek Well Services, LP, an entity in which two of our Sponsors (EIG and Tailwater) have an indirect controlling interest, for servicing work it performed for us.

During the second quarter of 2013, we issued and sold 1,715,000 Series A Preferred Units to Southcross Energy LLC for a cash purchase price of $22.86 per Series A Preferred Unit, in a privately negotiated transaction (See Note 11). After the Series A Preferred Units issuance during the second quarter of 2013, Southcross Energy LLC sold 1,500,000 of the units to third parties. All of the Series A Preferred Units, including those held by Southcross Energy LLC, were converted into common units on August 4, 2014 in connection with the Holdings Transaction. See Notes 1 and 11.

Wells Fargo Bank, N.A.

Under our Senior Credit Facilities, Wells Fargo Bank, N.A. serves as the administrative agent (and served in that same capacity under our Previous Credit Facility). See Note 8. An affiliate of Wells Fargo Bank, N.A. is a member of our investor group. We entered into amendments to our Previous Credit Facility during 2013 and 2014. In addition, in connection with the TexStar Rich Gas System Transaction, during the third quarter of 2014, we entered into the Senior Credit Facilities, which include syndicates of financial institutions and other lenders. Affiliates of Wells Fargo Bank, N.A. have from time to time engaged in commercial banking and financial advisory transactions with us in the normal course of business. During the year ended December 31, 2014, 2013 and 2012, we incurred costs, excluding interest, to Wells Fargo Bank, N.A. and its affiliates of $9.5 million, $1.8 million and $5.9 million, respectively (See Notes 1 and 8).

Other Transactions with Affiliates

Under the Distribution Agreement, we made customary representations, warranties and agreements, including an agreement to indemnify the Managers for certain liabilities under the Securities Act. The Managers and certain of their affiliates have engaged, and may in the future engage, in commercial and investment banking transactions with us in the ordinary course of their business for which they have received, and expect to receive, customary compensation and expense reimbursement. In particular, affiliates of each of the Managers are lenders under our Senior Credit Facilities, an affiliate of Wells Fargo Securities, LLC is a lender under our Term Loan and affiliates of the other sales agents may from time to time hold positions in the Term Loan. If we use any net proceeds of this offering to repay borrowings under our Senior Credit Facilities, such affiliates of the Managers will receive proceeds of the offering.

In conjunction with the TexStar Rich Gas System Transaction, we entered into a gas gathering and processing agreement (the “G&P Agreement”) and an NGL sales agreement (the “NGL Agreement”) with an affiliate of Holdings. Under the terms of these agreements, we transport, process and sell rich natural gas for the affiliate of Holdings in return for fees that are substantially equivalent to the fees that Holdings receives from its customers for such services, and we can sell natural gas liquids that we own to Holdings at prices that are substantially equivalent to prices that Holdings receives from third parties. In the future, when Holdings’ fractionation facility is operational, the NGL Agreement will permit us to utilize Holdings’ fractionation services at market-based rates.

10. TRANSACTIONS WITH RELATED PARTIES (Continued)

During the year ended December 31, 2014, the Partnership recorded revenues from affiliates of $13.3 million in accordance with the G&P Agreement and the NGL Agreement. Accounts receivable due from affiliates of $11.3 million as of December 31, 2014 is comprised of primarily (a) $5.8 million due from Holdings relating to gathering and processing services in the period and (b) $2.8 million and $2.3 million due from T2 Cogen and T2 Gas Utilities respectively (as defined in Note 16) representing reimbursements for operating costs and equipment for this investment in joint ventures. Accounts payable due to affiliates of $12.9 million as of December 31, 2014 is comprised of primarily (a) $5.4 million due to Holdings relating to reimbursements of insurance and capital costs and (b) $4.6 million due to T2 Cogen, T2 Gas Utility, and T2 La Salle Gas Utility representing operational obligations.

11. SERIES A CONVERTIBLE PREFERRED UNITS

We entered into a Series A Convertible Preferred Unit Purchase Agreement (the “Purchase Agreement”) with Southcross Energy LLC, pursuant to which we issued and sold 1,715,000 Series A Preferred Units to Southcross Energy LLC during the second quarter of 2013 for a cash purchase price of $22.86 per unit, in a privately negotiated transaction (the “Private Placement”). Southcross Energy LLC sold 1,500,000 of these Series A Preferred Units to third parties during the second quarter of 2013. The Private Placement of Series A Preferred Units resulted in proceeds to us of $39.2 million. We also received a $0.8 million capital contribution from our General Partner to maintain its 2.0% general partner interest in us. Our total capital infusion of $40.0 million, from all sales of Series A Preferred Units and General Partner capital contributions, was used to reduce borrowings under our Previous Credit Facility (See Note 8).

All of the Series A Preferred Units, including units held by Southcross Energy LLC, were converted to common units on August 4, 2014 in connection with the Holdings Transaction. See Note 1 and below.

Because the Series A Preferred Units were equity instruments and redeemable at the option of the holder, they were classified outside of permanent equity. The change of control rights associated with the Series A Preferred Units required the units to be classified outside of permanent equity. The Series A Preferred Units were periodically adjusted to maximum redemption value because maximum redemption value was different than the fair value of the unit at the issuance date.

Voting Rights: The Series A Preferred Units were a class of voting equity security that rank senior to all of our other classes or series of equity securities with respect to distribution rights and rights upon liquidation. The Series A Preferred Units had voting rights identical to the voting rights of the common units and voted with the common units as a single class, such that each Series A Preferred Unit (including each Series A Preferred Unit issued as an in-kind distribution, discussed below) was entitled to one vote for each common unit into which such Series A Preferred Unit was convertible on each matter with respect to which each common unit was entitled to vote.

Distribution Rights: Holders of Series A Preferred Units were entitled to quarterly distributions of in-kind Series A Preferred Units for the first four full quarters following the issue date of those units and continuing thereafter until the board of directors of our General Partner determined to begin paying quarterly distributions in cash, and thereafter in cash. In-kind distributions were in the form of Series A Preferred Units at a rate of $0.40 per outstanding Series A Preferred Unit per quarter (or 7% per year of the per unit purchase price). Cash distributions equaled the greater of $0.40 per unit per quarter or the quarterly distribution paid with respect to each common unit.

11. SERIES A CONVERTIBLE PREFERRED UNITS (Continued)

Conversion Rights: The Series A Preferred Units were convertible into common units based on an exchange ratio of 110% of the Series A Preferred Units in certain circumstances before January 1, 2015. In connection with the Holdings Transaction and pursuant to the change in control provision in our partnership agreement applicable to our Series A Preferred Units, all holders of the Series A Preferred Units elected to convert their Series A Preferred Units into 2,015,638 common units based on the 110% exchange ratio.

Dissolution and Liquidation: The Series A Preferred Units were senior to our common units with respect to rights on dissolution and liquidation. Common units issued upon conversion of the Series A Preferred Units have equal ranking with the rest of our common units with respect to rights on dissolution and liquidation.

12. PARTNERS' CAPITAL AND MEMBERS' EQUITY

Ownership

Our units outstanding as of December 31, 2014 are as follows (in units):

		Partners' Capital					
			Owned By Parent				
	Series A Preferred	Public Common	Holdings Common	Class B Convertible	Subordinated	General Partner
Units outstanding as of December 31, 2013	1,769,915	10,390,272	—	—	12,213,713	534,638
Issuance of common units	—	9,200,000	—	—	—	187,755
Holdings Transaction	—	—	1,863,713	—	—	—
Series A Convertible preferred conversion to common units	(1,832,399)	1,762,951	252,687	—	—	—
Issuance of Class B Convertible Units	—	—	—	14,633,000	—	—
Vesting of LTIP units, net	—	331,320	—	—	—	—
In-kind distributions and general partner issuances to maintain 2.0% ownership	62,484	—	—	256,078	—	316,459
Units outstanding as of December 31, 2014	—	21,684,543	2,116,400	14,889,078	12,213,713	1,038,852

On November 7, 2012, we completed our IPO. Through a series of transactions, Southcross Energy LLC contributed all of its operating subsidiaries (its net assets on a historical cost basis), excluding certain liabilities and all preferred units, and became the holding company of us. Until the Holdings Transaction, Southcross Energy LLC held all of the equity interests in our General Partner, as well as all subordinated units and a portion of the common units and Series A Preferred Units of us. Subsequent to our IPO, we own Southcross Energy LLC's operating subsidiaries. At the completion of our IPO, we received proceeds of approximately $168.0 million, net of underwriters' discounts and structuring fees. In connection with the full exercise of the underwriter's over-allotment option, which closed on November 26, 2012, our underwriters purchased 1,350,000 additional common units in us for approximately $25.2 million in proceeds, net of underwriters' and structuring fees; and we used the net proceeds of $25.2 million to reacquire 1,350,000 common units from Southcross Energy LLC and retired the common units.

12. PARTNERS' CAPITAL AND MEMBERS' EQUITY (Continued)

On November 29, 2013, we filed a Registration Statement on Form S-3 with the SEC using a "shelf" registration process. Under the shelf registration process, we may over time, in one or more offerings, offer and sell any combination of the securities described in the prospectus, and the selling unitholders may, over time, in one or more offerings, offer and sell common units representing limited partner interests in us. We, together with Southcross Energy Finance Corp., may offer and sell debt securities described in the prospectus. Southcross Energy Finance Corp. may act as co-issuer of the debt securities, and certain direct or indirect subsidiaries of us may guarantee any debt securities offered, if and to the extent identified in the related prospectus supplement. The aggregate initial offering price of all securities sold by us under the prospectus will not exceed $675.0 million.

Common units

Our common units represent limited partner interests in us. The holders of our common units are entitled to participate in our distributions and are entitled to exercise the rights and privileges available to limited partners under our Partnership Agreement.

In February 2014, we completed a public equity offering of 9,200,000 additional common units and we received a capital contribution from our General Partner to maintain its 2.0% interest in us. The proceeds from the public offering were $144.7 million, before estimated expenses related to the offering of $0.4 million. The net proceeds from the offering were used for our Onyx acquisition in March 2014, to fund the construction of our Webb Pipeline and for general partnership purposes.

In connection with the TexStar Rich Gas System Transaction and the Holdings Transaction on August 4, 2014, we issued Class B Convertible Units, accelerated the vesting of awards under our LTIP, and all of the holders of our Series A Preferred Units elected to convert their Series A Preferred Units into common units based on an exchange ratio of 110%.

Class B Convertible Units

In connection with the Contribution, on August 4, 2014, we established our Class B Convertible Units. The Class B Convertible Units consist of 14,633,000 of such units plus any additional Class B PIK Units. The Class B Convertible Units have the same rights, preferences and privileges, and are subject to the same duties and obligations, as our common units, with certain exceptions as noted below.

Our Partnership Agreement does not allow additional Class B Convertible Units (other than Class B PIK Units) to be issued without the prior approval of our General Partner and the holders of a majority of the outstanding Class B Convertible Units.

Our Partnership Agreement provides that we will procure the listing of the common units issuable upon conversion of the Class B Convertible Units on the New York Stock Exchange or other applicable national securities exchange.

Distribution Rights: Commencing with the third quarter of 2014 and until converted, as long as certain requirements are met, the holders of the Class B Convertible Units will receive quarterly distributions in an amount equal to $0.3257 per unit. These distributions will be paid quarterly in Class B PIK Units within 45 days after the end of each quarter. Our General Partner was entitled, and has exercised its right, to retain its 2.0% general partner interest in us in connection with the original issuance of Class B Convertible Units. In connection with future distributions of Class B PIK Units, the General Partner is entitled to a corresponding distribution to maintain its 2.0% general partner interest in us.

12. PARTNERS' CAPITAL AND MEMBERS' EQUITY (Continued)

Conversion Rights: The Class B Convertible Units are convertible into common units on a one-for-one basis and, once converted, will participate in cash distributions pari passu with all other common units. The conversion of Class B Convertible Units will occur on the date we (a) make a quarterly distribution equal to or greater than $0.44 per common unit, (b) generate Class B Distributable Cash Flow (as defined in our Partnership Agreement) in an amount sufficient to pay the declared distribution on all units for the two quarters immediately preceding the date of conversion (the "measurement period") and (c) forecast paying a distribution equal to or greater than $0.44 per unit from forecasted Class B Distributable Cash Flow on all outstanding common units for the two quarters immediately following the measurement period.

Voting Rights: The Class B Convertible Units generally have the same voting rights as common units, and have one vote for each common unit into which such units are convertible.

Changes in Partners' Capital due to Holdings Transaction

As discussed in Note 1, on August 4, 2014, Southcross Energy LLC and TexStar combined. As a result of this transaction, Holdings, through a wholly-owned subsidiary, (a) acquired 100% of TexStar and its general partner from BBTS Borrower LP and (b) acquired 2,116,400 of our common units and 12,213,713 of our subordinated units from Southcross Energy LLC. Thus, as a result of that transaction, Holdings acquired an approximate 57.4% limited partner interest in us, as well as 100% of our General Partner, which owns an approximate 2.0% interest in us and our incentive distribution rights. BBTS Borrower LP is controlled by EIG and Tailwater. In November 2014, BBTS Borrower LP distributed to each of EIG and Tailwater, in relatively equal proportions, its interest in Holdings. Southcross Energy LLC is controlled by Charlesbank. The Holdings Transaction resulted in the Sponsors each indirectly owning approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine Opportunities Fund and GE Energy Financial Services own certain additional ownership interests in Holdings as well.

Subordinated units

Subordinated units represent limited partner interests in us and convert to common units at the end of the Subordination Period (as defined in our Partnership Agreement). The principal difference between our common units and our subordinated units is that in any quarter during the Subordination Period, holders of the subordinated units are not entitled to receive any distribution of available cash until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units do not accrue arrearages. Beginning with the third quarter of 2014, until such time we have a Distributable Cash Flow Ratio of at least 1.0, Holdings, the holder of the subordinated units, has waived the right to receive distributions on any subordinated units that would cause the Distributable Cash Flow Ratio to be less than 1.0. With respect to the fourth quarter of 2014, Holdings waived the requirement that any distribution owed to it for that quarter be paid within 45 days of the end of the quarter, provided that the distribution is paid before or in conjunction with the filing of this Form 10-K.

General Partner Interests

As defined by the Partnership Agreement, general partner units are not considered to be units (common or subordinated), but are representative of our general partner's 2.0% ownership interest in us. Our General Partner has received general partner unit PIK distributions from our general partner units purchased in connection with the sale of the Series A Preferred Units (See Note 11) and the Class B Convertible Units. In connection with other equity issuances, including issuances related to the TexStar Rich Gas System Transaction and the Holdings

12. PARTNERS' CAPITAL AND MEMBERS' EQUITY (Continued)

Transaction, our General Partner has made capital contributions in exchange for an issuance of additional general partner units to maintain its 2.0% ownership interest in us. Also, the General Partner has received general partner unit PIK distributions from the general partner units purchased in connection with the Private Placement (See Note 11).

Equity Distribution Agreement

On November 12, 2014, we established a $75 million "at-the-market" equity offering program pursuant to an equity distribution agreement (the "Distribution Agreement") with Wells Fargo Securities, LLC, J.P. Morgan Securities LLC and RBC Capital Markets, LLC (each, a "Manager" and, collectively, the "Managers"). Under the Distribution Agreement, we may offer and sell up to $75 million in aggregate gross sales proceeds of our common units (the "Offered Units") from time to time through the Managers, each as our sales agent. Sales of the Offered Units, if any, made under the Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices prevailing at the time of sale in block transactions, or as otherwise agreed upon by us and any Manager. The Offered Units have been registered under the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Registration No. 333-192105, declared effective December 10, 2013, (the "Registration Statement"), including the prospectus contained therein, as supplemented by the prospectus supplement filed with the SEC on November 12, 2014. We intend to use the net proceeds from the sale of the Offered Units for general partnership purposes, including the repayment of debt, acquisitions and funding capital expenditures.

The Distribution Agreement contains customary representations, warranties and agreements by us, including our obligations to indemnify the Managers for certain liabilities under the Securities Act. The Managers and certain of their affiliates have engaged, and may in the future engage, in commercial and investment banking transactions with us in the ordinary course of their business for which they have received, and expect to receive, customary compensation and expense reimbursement. In particular, affiliates of each of the Managers are lenders under our Senior Credit Facilities, an affiliate of Wells Fargo Securities, LLC is a lender under our Term Loan and affiliates of the other sales agents may from time to time hold positions in the Term Loan. If we use any net proceeds of this offering to repay borrowings under our Senior Credit Facilities, such affiliates of the Managers will receive proceeds of the offering.

Members' Equity of Southcross Energy LLC

On August 6, 2009, five members of the Southcross Energy LLC's management team purchased, directly or indirectly through Estrella Energy, LP, Class A common units and Class B units along with Charlesbank, for the same value as Charlesbank, ($1.00 per unit). Estrella Energy, LP was partially owned by a non-management third-party, and thus a portion of the time- and performance-based units ("Third-Party Units") owned by Estrella Energy, LP were owned indirectly by the non-management third-party.

As of December 31, 2011, Southcross Energy LLC's common equity was comprised of 1,415,729 Class A authorized and outstanding common units, of which 217,483 were unvested, and 57,279 authorized and outstanding Class B units, of which 34,367 were unvested. The Class B units have the same distribution and liquidation rights as the Class A common units; however, they do not have voting rights. All Class A common units and Class B units were sold for, and have a par value of, $1.00 per unit.

Certain of the Class A common units and all of the Class B units contain time- and performance-vesting conditions. Time-vesting units vest ratably over 5 years subject to certain accelerated vesting based primarily on change of control or certain termination causes. Performance-vesting units will vest, if at all, upon Charlesbank

12. PARTNERS' CAPITAL AND MEMBERS' EQUITY (Continued)

attaining certain investment multiples and internal rates of return in connection with a liquidity event. Both the time- and performance vesting units require continued employment through any vesting date. The change in structure and ownership as a result of our IPO did not create a change of control event under the terms of the time- and performance-vesting units.

On March 20, 2012, Estrella Energy, LP was dissolved and Southcross Energy LLC purchased and retired the Third-Party Units for $15.3 million. Management did not receive any consideration in connection with such repurchase.

13. SOUTHCROSS ENERGY LLC PREFERRED UNITS

In connection with our IPO and through a series of transactions described in Note 12, Southcross Energy LLC contributed all of its operating subsidiaries (its net assets on a historical cost basis), excluding certain liabilities, common units and all preferred units, and became the holding company of us. This note discloses Southcross Energy LLC's preferred units as of November 7, 2012 (our IPO date), as well as the activity associated with the preferred units for the period from January 1, 2012 through our IPO.

None of the preferred units (Preferred, Redeemable Preferred and Series B Redeemable Preferred) were conveyed in our IPO, and remained the obligation of Southcross Energy LLC and not us. All of the Redeemable Preferred Units and Series B Redeemable Preferred Units have since been redeemed.

Preferred Units

As of November 7, 2012, Southcross Energy LLC's cumulative preferred units were comprised of 11,850,374 units with a par value of $10 per unit, which accrued value (in the form of additional preferential rights to receive distributions) at a rate of 10% per annum, compounded quarterly.

Except in the case of cash distributions made for the purpose of paying federal income taxes, which are made to both preferred and common equity owners in direct proportion to the owners' respective share of taxable income, owners of the preferred equity receive cash distributions before owners of common equity. The cumulative preferred units and their cumulative return are subordinated to all redeemable preferred units and their cumulative return as discussed below. With the exception of cash distributions for federal income tax purposes, the Credit Agreement included certain covenants that restricted Southcross Energy LLC's ability to pay cash dividends to its owners. Southcross Energy LLC adjusts the carrying value of the Preferred Units to reflect the cumulative right to receive distributions on a quarterly basis. As of November 7, 2012, and December 31, 2011, the preferred units' cumulative right to receive future cash distributions was $43.3 million and $31.8 million, respectively, as a result of the cumulative preferred return on such units.

Redeemable Preferred Units

As mentioned above, none of the redeemable preferred units were conveyed in our IPO, and they remained the obligation of Southcross Energy LLC. On June 10, 2011, in connection with Southcross Energy LLC entering into the Credit Agreement, Charlesbank and certain of Southcross Energy LLC's existing investors contributed a total of $15.0 million in exchange for 1.5 million Redeemable Preferred Units. The Redeemable Preferred Units had a par value of $10 per unit and accrued value (in the form of an additional preferential right to receive distributions) at a rate of 18% per annum, compounded quarterly. These Redeemable Preferred Units could be redeemed in whole or in part at any time, or would be redeemed by Southcross Energy LLC promptly after the satisfaction of all obligations under the Credit Agreement, to the extent of available funds. Southcross Energy LLC adjusted the carrying value of the Redeemable Preferred Units to reflect the cumulative right to

13. SOUTHCROSS ENERGY LLC PREFERRED UNITS (Continued)

receive distributions on a quarterly basis. As of November 7, 2012, the right of the Redeemable Preferred Units to receive future cash distributions included an additional $3.9 million as a result of the cumulative preferred return on such units. All of the Redeemable Preferred Units have since been redeemed.

Series B Redeemable Preferred Units

As mentioned above, none of the redeemable preferred units were conveyed in our IPO, and they remained the obligation of Southcross Energy LLC. On March 20, 2012, Charlesbank and certain of Southcross Energy LLC's existing investors contributed $25.3 million and an affiliate of Wells Fargo Securities, LLC contributed $10.0 million to Southcross Energy LLC in exchange for 2.53 million units and 1.0 million units, respectively, of a new, Series B class, of Redeemable Preferred Units ("Series B Units"). On June 26, 2012, Charlesbank and certain of Southcross Energy LLC's existing investors contributed $7.5 million to Southcross Energy LLC in exchange for 0.75 million Series B Units.

On November 7, 2012 and subsequent to our IPO, the Series B Units were comprised of 3.35 million units. On November 26, 2012 and subsequent to the Over-Allotment Option, Southcross Energy LLC redeemed 2.49 million units. The Series B Units have a par value of $10 per unit, which accrued value (in the form of an additional preferential right to receive distributions) at a rate of 18% per annum, compounded quarterly. The Series B Units could be redeemed by Southcross Energy LLC in whole or in part at any time, or would be redeemed by Southcross Energy LLC promptly after the satisfaction of all its obligations under the Credit Agreement, to the extent of available funds. Southcross Energy LLC adjusts the carrying value of the Series B Units to reflect the cumulative right to receive distributions on a quarterly basis. As of November 7, 2012 and November 26, 2012, the Series B Units' right to receive future cash distributions included $3.8 million and $4.4 million, respectively as a result of the cumulative preferred return. All of the Series B Units have since been redeemed.

Series C Redeemable Preferred Units

As mentioned above, none of the redeemable preferred units were conveyed in our IPO, and they remained the obligation of Southcross Energy LLC. On June 26, 2012, Charlesbank and certain of Southcross Energy LLC's existing investors and other institutional investors contributed $30.0 million to Southcross Energy LLC in exchange for 3.0 million units of a new, Series C class, of Redeemable Preferred Units ("Series C Units"). As of November 7, 2012, the Series C Units were comprised of 3.0 million units with a par value of $10 per unit, which accrue value (in the form of an additional preferential right to receive distributions) at a rate of 18% per annum, compounded quarterly. The Series C Units and their cumulative preferred return of $1.4 million as of November 7, 2012 were fully redeemed in connection with our IPO (See Note 12).

14. INCENTIVE COMPENSATION

Unit Based Compensation

Long-Term Incentive Plan

On November 7, 2012, and in connection with our IPO, we established the LTIP, which provides incentive awards to eligible officers, employees and directors of our General Partner. Awards granted to employees under the LTIP vest over a three year period in equal annual installments or in the event of a change in control of our General Partner in either a common unit or an amount of cash equal to the fair market value of a common unit at the time of vesting, as determined by management at its discretion. These awards also include distribution equivalent rights that grant the holder the right to receive an amount equal to the cash distributions on common units during the period the award remains outstanding.

14. INCENTIVE COMPENSATION (Continued)

The following table summarizes information regarding awards of units granted under the LTIP:

	Units	Weighted-Average Fair Value at Grant Date
Unvested—November 7, 2012	—	$ —
Granted units	146,000	23.01
Forfeited units	(1,500)	23.01
Vested units	—	—
Unvested—December 31, 2012	**144,500**	**$23.01**
Granted units	112,179	21.96
Forfeited units	(20,700)	22.09
Units recaptured for tax withholdings	(13,034)	23.01
Vested units	(40,272)	22.30
Unvested—December 31, 2013	**182,673**	**$22.55**
Granted units	787,321	19.82
Forfeited units	(1,050)	23.01
Units recaptured for tax withholdings	(159,500)	17.06
Vested units	(338,694)	17.45
Unvested—December 31, 2014	**470,750**	**$20.47**

For the years ended December 31, 2014 and 2013, we granted awards under the LTIP, with a grant date fair value of $15.6 million and $2.5 million, respectively, which we have classified as equity awards. As of December 31, 2014 and 2013, we had total unamortized compensation expense of $9.1 million and $3.6 million, respectively, related to these units. The awards were expected to be amortized over the three-year vesting period from each equity award's grant date. The Holdings Transaction on August 4, 2014 resulted in a change of control of our General Partner and accelerated the vesting of all the LTIP awards and distribution equivalent rights outstanding on that date. As of December 31, 2014 and 2013, we had 900,284 and 1,527,055 units, respectively, available for issuance under the LTIP.

Unit Based Compensation Expense

The following table summarizes information regarding recognized compensation expense, which is included in general and administrative and operations and maintenance expense on our statements of operations (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Unit-based compensation	$10,074[(1)]	$2,186	$630

(1) This amount includes $7.2 million related to the accelerated vesting of the LTIP awards and $0.1 million related to the vesting of the Southcross Energy LLC equity equivalent units as a result of the change in control that took place on August 4, 2014.

14. INCENTIVE COMPENSATION (Continued)

Southcross Energy LLC Phantom Units

Southcross Energy LLC provided certain key non-officer employees with equity incentive units (“Phantom Units”) in Southcross Energy LLC. The Phantom Units vest upon the occurrence of a change in control where more than 50% of the voting power of Southcross Energy LLC changes hands, or upon the occurrence of a liquidity event where, through the sale of some portion of its ownership, the majority owner of Southcross Energy LLC achieves or exceeds a targeted rate of return on its original investment. The changes in structure and ownership as a result of our IPO did not create a change of control event under the vesting terms of the Phantom Units. The number of Phantom Units earned and eligible for vesting increases over a period of years or through the achievement of certain rates of return by the majority owner of the Southcross Energy LLC or a combination thereof. As of December 31, 2014 and 2013, no fair value was attributable to the Phantom Units. No compensation expense associated with these units was recorded during the year ended December 31, 2014 and 2013. As of December 31, 2013, the number of authorized and issued Phantom Units was 10,832.

Southcross Energy LLC Equity Equivalent Units

On April 1, 2012, Southcross Energy LLC granted 15,000 equity equivalent units (“EEUs”) to a member of management. Each individual EEU is equivalent in economic value to one Class A Common Unit of Southcross Energy LLC on a fully diluted basis. The EEUs had time and performance vesting over a three year term. In conjunction with the closing of the Holdings Transaction, the 15,000 outstanding EEUs subject to change of control provisions vested on August 4, 2014. The Partnership recognized $0.1 million in general and administrative expenses in the statements of operations for the year ended December 31, 2014 in connection with the accelerated vesting of the EEUs. Compensation expense for the EEUs recognized in general and administrative expenses on the statements of operation was $0.6 million and $0.4 million for the year ended December 31, 2013 and 2012, respectively.

Employee Savings Plan

We have employee savings plans under Sections 401(a) and 401(k) of the Internal Revenue Code, as amended, whereby employees of our General Partner may contribute a portion of their base compensation to the employee savings plan, subject to limits. We provide a matching contribution each payroll period equal to 100% of the employee’s contribution up to the lesser of 6% of the employee’s eligible compensation or $17,500 annually for the period. The following table summarizes information regarding contributions and the expense recognized for the matching contributions, which is included in general and administrative expense on our statements of operations (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Matching contributions expensed for employee savings plan . . .	$927	$628	$512

2014 Incentive Plan

On August 4, 2014, our General Partner and Southcross GP Management Holdings, LLC, a newly formed entity of which Holdings is the sole managing member (“GP Management”), adopted the Southcross Energy Partners GP, LLC and Southcross GP Management Holdings, LLC 2014 Equity Incentive Plan (the “2014 Incentive Plan”). Under the 2014 Incentive Plan, employees, consultants and directors of our General Partner and GP Management will be eligible to receive incentive compensation awards.

The 2014 Incentive Plan generally provides for the grant of awards, from time to time at the discretion of the board of directors of our General Partner (and, as applicable, the board of directors of the general partner of

14. INCENTIVE COMPENSATION (Continued)

Holdings), of non-voting units in our General Partner to GP Management and then a corresponding grant or award of non-voting units of GP Management to the employee, consultant or director.

In connection with the adoption of the 2014 Incentive Plan, our General Partner amended and restated its limited liability company agreement and entered into its Second Amended and Restated Limited Liability Company Agreement which establishes a new class of non-voting units for issuance pursuant to the 2014 Incentive Plan and designates Holdings as our General Partner's managing member. As of December 31, 2014, no awards had been granted under this plan.

15. REVENUES

We had revenues consisting of the following categories (in thousands):

	Year ended December 31,		
	2014	2013	2012
Sales of natural gas	$530,947	$405,206	$325,421
Sales of NGLs and condensate	226,218	169,523	124,139
Transportation, gathering and processing fees	85,021	59,392	46,113
Other	541	601	456
Total revenues	$842,727	$634,722	$496,129

16. INVESTMENTS IN JOINT VENTURES

Assets acquired through the TexStar Rich Gas System Transaction include equity interests in three joint ventures. During 2012, a subsidiary of TexStar and a company subsequently acquired by Atlas Pipeline Partners, L.P. formed T2 Eagle Ford Gathering Company LLC ("T2 Eagle Ford"), T2 LaSalle Gathering Company LLC ("T2 LaSalle") and T2 EF Cogeneration Holdings LLC ("T2 Cogen") to construct and operate a pipeline and cogeneration facility located in South Texas. The Partnership indirectly has a 50% interest in T2 Eagle Ford, a 50% interest in T2 Cogen and a 25% interest in T2 LaSalle. The joint ventures' summarized financial data from their statements of operations since we obtained our equity interests in the joint ventures on August 4, 2014 is as follows (in thousands):

	Year Ended December 31, 2014		
	T2 Eagle Ford	T2 Cogen	T2 LaSalle
Revenue	$ 3,537	$ 2,517	$ 1,163
Net loss	(6,277)	(4,281)	(1,876)

The Partnership's equity in losses of joint venture investments is comprised of the following for the year ended December 31, 2014 (in thousands):

	Year Ended December 31, 2014
T2 Eagle Ford	$(3,656)
T2 Cogen	(2,141)
T2 LaSalle	(699)
Equity in losses of joint venture investments	$(6,496)

16. INVESTMENTS IN JOINT VENTURES (Continued)

The Partnership's investments in joint ventures is comprised of the following as of December 31, 2014 (in thousands):

	December 31, 2014
T2 Eagle Ford	$108,185
T2 Cogen	19,615
T2 LaSalle	19,298
Investments in joint ventures	$147,098

The joint ventures' summarized financial data from their balance sheets as of December 31, 2014 is as follows (in thousands):

	Year Ended December 31, 2014		
	T2 Cogen	T2 Eagle Ford	T2 LaSalle
Current assets	$ 8,923	$ 4,173	$ 904
Property, plant and equipment, net	38,851	216,863	77,189
Total assets	47,774	221,036	78,093
Total liabilities	8,547	3,915	904
Total equity	39,227	217,121	77,189
Total liabilities and equity	$47,774	$221,036	$78,093

17. CONCENTRATION OF CREDIT RISK

Our primary markets are in South Texas, Alabama and Mississippi. We have a concentration of revenues and trade accounts receivable due from customers engaged in the production, trading, distribution and marketing of natural gas and NGL products. These concentrations of customers may affect overall credit risk in that these customers may be affected similarly by changes in economic, regulatory or other factors. We analyze our customers' historical financial and operational information before extending credit.

Our top ten customers for the years ended December 31, 2014, 2013 and 2012 represent the following percentages of consolidated revenue:

	Year Ended December 31,		
	2014	2013	2012
Top ten customers	63.9%	59.7%	65.5%

The percentage of total consolidated revenue for each customer that exceeded 10% of total revenues for the years ended December 31, 2014, 2013 and 2012 was as follows:

	Year Ended December 31,		
	2014	2013	2012
Trafigura AG	13.7%	11.7%	11.0%
Formosa Hydrocarbons Co., Inc.	(a),(b)	(a),(b)	24.3%

(a) Information is not provided for periods for which the customer or producer was less than 10% of our consolidated revenue.

(b) Our contract with Formosa terminated on June 1, 2013.

17. CONCENTRATION OF CREDIT RISK (Continued)

During the years ended December 31, 2014, 2013 and 2012, we did not experience significant non-payment for services. At December 31, 2014, 2013 and 2012, we did not record an allowance for uncollectible accounts receivable.

18. SUBSEQUENT EVENTS

Partnership Distribution

On January 22, 2015, the board of directors of our General Partner declared a cash distribution of $0.40 per common unit and General Partner unit, which was paid on February 13, 2015 to unitholders of record on February 9, 2015. In addition, on January 22, 2015, the board of directors of our General Partner declared a $0.3257 per unit distribution for the fourth quarter of 2014 on the Partnership's Class B Convertible Units. The distribution on the Class B Convertible Units was paid in the form of additional Class B Convertible Units on February 13, 2015. In order to support the Partnership's recent acquisition of the TexStar Rich Gas System in August 2014, Holdings has elected to forgo distributions on any subordinated units that would cause the Partnership's distributions to exceed its distributable cash flow for any quarterly period. This election will continue until the Partnership has distributable cash flow in excess of total distributions on the Partnership's common and subordinated units. Holdings has also elected to defer any distribution that is expected to be payable on the subordinated units for the fourth quarter of 2014 until the Partnership files its Form 10-K for its fiscal year ended December 31, 2014. We intend to make a cash distribution with respect to the subordinated units for the fourth quarter of 2014 such that the total of the subordinated, common and cash pay general partner unit distributions is equal to the Partnership's distributable cash flow for such period.

On January 20, 2015, we experienced a fire at our Gregory facility, the exact cause of which is being investigated. There were no injuries in connection with the fire and damage was limited to one of our two processing units at the facility.

The Gregory facility includes 135 MMcf/d of gas processing capacity from two processing units with 80 MMcf/d and 55 MMcf/d of capacity, respectively, and an associated 4,800 barrel per day fractionation plant. Damage appears to be limited to the 80 MMcf/d processing unit. The Gregory facility was shut down as a result of the fire for four weeks, and after completing safety reviews, the 55 MMcf/d processing unit was restarted.

We do not anticipate a material financial impact as a result of the fire and outage. We maintain insurance that carries a $500,000 deductible and is expected to cover any repair costs in excess of the deductible.

The Compensation Committee of the Board of Directors authorized future grants, to be made on March 10, 2015, of phantom units to the executive officers of our General Partner, if such persons remain employed as of such date (the "2015 LTIP Awards"). The number of phantom units to be granted as 2015 LTIP Awards, if at all, will be determined by dividing the award value by the closing price of our common units on March 10, 2015. All of the foregoing phantom unit awards will be made under our LTIP, which is described in Note 14; however, certain awards will have a one-year vesting period rather than a three-year vesting period. These awards are not compensation earned for performance in 2014. See Note 14 for additional information regarding the LTIP.

19. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2014	2013	2012
Supplemental Disclosures:			
Cash paid for interest	$ 16,206	$13,043	$10,552
Cash received for tax refunds	205	95	315
Supplemental schedule of non-cash investing and financing activities:			
Accounts payable related to capital expenditures	21,622	4,946	40,707
Change in value recognized in other comprehensive income	11	148	745
Capital lease obligation	708	1,396	—
Accrued distribution equivalent rights on the LTIP units	167	279	—
Series A Convertible preferred unit in-kind distributions and fair value adjustments	5,130	—	—
Class B Convertible unit issuance, net	324,413	—	—
Class B Convertible unit in-kind distributions	9,610	—	—
Consideration paid in excess of purchase price for the TexStar Rich Gas System	98,625	—	—
Settlement of EEU liability by Southcross Energy LLC	1,151	—	—

SUPPLEMENTAL SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following presents a summary of selected quarterly financial information (in thousands, except per unit data):

	Quarters ended			
2014	**March 31**	**June 30**	**September 30**	**December 31**
Revenues	$213,591	$195,063	$211,493	$222,580
Gross operating margin	27,188	26,237	30,931	37,239
(Loss) income from operations	1,692	(1,134)	(14,403)	7,026
Net loss	(1,289)	(2,961)	(24,778)[1]	(2,294)
Basic and diluted net loss per common unit	(0.06)	(0.34)	(0.49)	(0.05)
Basic and diluted net loss per subordinated unit	(0.06)	(0.11)	(0.49)	(0.05)

	Quarters ended			
2013	**March 31**	**June 30**	**September 30**	**December 31**
Revenues	$144,250	$154,703	$160,629	$175,140
Gross operating margin	18,863	21,296	25,213	28,174
(Loss) income from operations	(4,317)	(2,831)	(357)	4,510
Net (loss) income	(6,382)	(6,192)	(4,069)	673
Basic net (loss) income per common unit	(0.26)	(0.65)	0.19	(0.01)
Diluted net loss per common unit	(0.26)	(0.65)	(0.14)	(0.01)
Basic and diluted net loss per subordinated unit	(0.26)	(0.27)	(0.19)	(0.01)

(1) See Note 4 to the consolidated financial statements.

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of the chief executive officer (principal executive officer) and chief financial officer (principal financial officer) of our General Partner, the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2014. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including to the chief executive officer and chief financial officer of our General Partner, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on this evaluation, the chief executive officer and chief financial officer of our General Partner have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Form 10-K.

Management's Report on Internal Control Over Financial Reporting

Our General Partner's management, including the chief executive officer and chief financial officer of our General Partner, is responsible for establishing and maintaining effective internal control over our financial reporting. Our internal control system was designed to provide reasonable assurance to our General Partner's management and to members of the board of directors of our General Partner regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our General Partner's management conducted an evaluation of the effectiveness of internal control over financial reporting based on the 1992 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our General Partner's management concluded that our internal control over financial reporting was effective as of December 31, 2014.

As more fully described in Note 1 to our consolidated financial statements, on August 4, 2014, contemporaneously with the closing of the Holdings Transaction, TexStar contributed the TexStar Rich Gas System to us through a contribution of TexStar's equity interest in the entities that own the TexStar Rich Gas System. We excluded the TexStar Rich Gas System from our 2014 assessment of the effectiveness of our internal control over financial reporting. The TexStar Rich Gas System accounted for approximately 34.8% and 5.7% of total assets and total liabilities, respectively, and 2.4% of operating revenues of our consolidated financial statement amounts as of and for the year ended December 31, 2014. We expect that our internal control system will be fully implemented for the TexStar Rich Gas System during 2015 and correspondingly evaluated by us for effectiveness.

As an emerging growth company, management's report on internal control over financial reporting was not subject to attestation by our independent registered public accounting firm in accordance with rules of the SEC that permit us to provide only the management's report in this Form 10-K.

Changes in Internal Control

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the fourth quarter ended December 31, 2014, which is covered by this Form 10-K, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

On March 5, 2015, our General Partner entered into an employment agreement with John E. Bonn, the President and Chief Executive Officer of our General Partner (the “Bonn Employment Agreement”). The Bonn Employment Agreement provides for an initial three-year term, unless earlier terminated. The Bonn Employment Agreement automatically extends for one year periods unless notice is given otherwise prior to the expiration of the then-current term. Mr. Bonn will receive an annual base salary of $450,000 for the first year, $500,000 for the second year and not less than $500,000 for each year thereafter, as determined by the board of directors of our General Partner. Mr. Bonn may receive an annual cash bonus based on annual performance targets in an amount determined by the board of directors of our General Partner in its discretion with a target annual bonus equal to Mr. Bonn’s salary for such year. In 2015, Mr. Bonn is entitled to receive a grant of LTIP with a fair market value of $200,000 (and if made, Mr. Bonn’s 2015 LTIP Award (as defined in Item 11 of this report) will satisfy this covenant). Mr. Bonn may also receive LTIP awards as determined by the board of directors of our General Partner with the target of the fair market value of the LTIP award equal to 150% of Mr. Bonn’s then-current annual salary. Mr. Bonn is also entitled to receive certain benefits and reimbursement of certain expenses, including relocation expenses.

Under the Bonn Employment Agreement, upon a termination of Mr. Bonn’s employment by us without “cause” or by Mr. Bonn for “good reason,” Mr. Bonn will be entitled to receive (i) an amount equal to two times his then-current annual base salary, (ii) an amount equal to two times his target annual bonus, (iii) an amount equal to the cost of COBRA coverage for 18 months after termination and (iv) an amount equal to $150,000 if terminated during the first year, $100,000 if terminated during the second year or $50,000 if terminated during the third year (and no additional payment if Mr. Bonn is terminated after the third year). The severance payment is subject to Mr. Bonn’s execution of a general release agreement and compliance with certain restrictions.

A for “cause” termination would occur under the Bonn Employment Agreement if (i) Mr. Bonn fails to perform satisfactorily his material duties or to devote his full time and effort to his position, (ii) violates any material company policy that remains un-remedied after reasonable notice to cure the violation, (iii) fails to follow lawful directives from our Chairman or the board of directors of our General Partner, (iv) his negligence or material misconduct, (v) his fraud, embezzlement, misappropriation, material misconduct, conversion of assets or breach of fiduciary duty or (vi) any felony conviction.

A “good reason” termination would be permitted under Mr. Bonn’s employment within 90 days after the following occurs (without Mr. Bonn’s written consent): (i) Mr. Bonn is removed as Chief Executive Officer, (ii) a material diminution of his base salary or (iii) a change in the location of Mr. Bonn’s employment that requires Mr. Bonn to relocate his residence to a location more than 50 miles from Dallas, Texas.

During his employment and for one year following his termination, Mr. Bonn is subject to certain non-competition and non-solicitation provisions set forth in the Bonn Employment Agreement. Mr. Bonn is also subject to certain confidentiality provisions during and after his employment.

The foregoing description of the Bonn Employment Agreement is not complete and is qualified in its entirety by reference to the full text of the Bonn Employment Agreement, which is attached as Exhibit 10.11 to this Form 10-K and incorporated herein by reference.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Southcross Energy Partners, L.P.

Southcross Energy Partners, L.P. is managed by the directors and executive officers of our General Partner. Our General Partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. Holdings owns 100% of our General Partner. Our General Partner has a board of directors, and our unitholders are not entitled to elect the directors or to directly or indirectly participate in our management or operations. Our General Partner will be liable, as the General Partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our General Partner.

Director Independence

Although most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a listed publicly traded master limited partnership like us to have a majority of independent directors on the board of directors of its general partner.

Committees of the Board of Directors

The board of directors of our General Partner has an Audit Committee, a Conflicts Committee and a Compensation Committee and may have any such other committee as the board of directors shall determine from time to time. Each of the standing committees of the board of directors of our General Partner has the composition and responsibilities described below.

Conflicts Committee

Jerry W. Pinkerton and Bruce A. Williamson serve as the members of our Conflicts Committee. Mr. Pinkerton serves as the chairman of the Conflicts Committee. Our Partnership Agreement provides that the Conflicts Committee, as delegated by the board of directors of our General Partner as circumstances warrant, will review conflicts of interest between us and our General Partner or between us and affiliates of our General Partner. If a matter is submitted to the Conflicts Committee for its review and approval, the Conflicts Committee will determine if the resolution of a conflict of interest that has been presented to it by the board of directors of our General Partner is fair and reasonable to us. The current members of the Conflicts Committee and any future members may not be officers or employees of our General Partner, directors, officers or employees of our General Partner's affiliates or a holder of any ownership interest in our General Partner, its affiliates or the Partnership, except for common units and certain awards given to directors in their capacity as a director. In addition, they must comply with the independence standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to have been approved in good faith, to be fair and reasonable to us, approved by all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders.

Audit Committee

Jerry W. Pinkerton, Ronald G. Steinhart and Bruce A. Williamson serve as the members of the Audit Committee. Mr. Pinkerton serves as the chairman of the Audit Committee. The Audit Committee oversees, reviews, acts on and reports on various auditing and accounting matters to the board of directors of our General Partner, including: (i) the selection of our independent accountants, (ii) the scope of our annual audits, (iii) fees to be paid to the independent accountants, (iv) the performance of our independent accountants, (v) the review of our internal controls process and (vi) our accounting practices. In addition, the Audit Committee oversees our compliance programs relating to legal and regulatory requirements. Messrs. Pinkerton, Steinhart and Williamson comply with the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Our General Partner is generally required to have at least three independent directors serving on its board of directors at all times. Messrs. Pinkerton and Steinhart are each audit committee financial experts.

Compensation Committee

Jon M. Biotti, Ronald G. Steinhart and Bruce A. Williamson serve as the members of the Compensation Committee. Mr. Biotti serves as the chairman of the Compensation Committee. The Compensation Committee establishes salaries, incentive compensation and other forms of compensation for officers, non-employee directors and other employees, as well as administers our incentive compensation and benefit plans.

Directors and Executive Officers

Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board of directors. The following table shows information for the directors and executive officers of our General Partner.

Name	Age	Position with Southcross Energy Partners GP, LLC
John E. Bonn	57	President and Chief Executive Officer
Phillip M. Mezey	56	Executive Vice President, Business Development
J. Michael Anderson	52	Senior Vice President and Chief Financial Officer
Donna A. Henderson	47	Vice President and Chief Accounting Officer
David W. Biegler	68	Chairman of the Board and Director
Jon M. Biotti	46	Director
Jason Downie	44	Director
Wallace Henderson	53	Director
Jerry W. Pinkerton	74	Director
Ronald G. Steinhart	74	Director
Bruce A. Williamson	55	Director

John E. Bonn

John E. Bonn was elected President and Chief Executive Officer of our General Partner in December 2014. Mr. Bonn also served as President and Chief Operating Officer from March 2014 to December 2014.

Before joining our General Partner in March 2014, Mr. Bonn, was president of NiSource Midstream Services LLC, a midstream services company and subsidiary of NiSource Inc., from April 2011 to June 2013, as well as President of Pennant Midstream, LLC, a midstream services company. While at NiSource, he was responsible for building its midstream business in the Appalachian Basin and successfully sourcing and overseeing midstream opportunities in the Marcellus and Utica shale plays, including natural gas gathering, processing and liquids handling. From January 2010 to March 2011, Mr. Bonn was the Owner and President of Ranger Interests, Inc. From 2006 to 2009, Mr. Bonn was Vice President of Enterprise Product Partners L.P., a midstream services company. Mr. Bonn has over 30 years of experience in the midstream energy sector and has held various management and senior leadership positions with various energy companies, including GulfTerra Energy Partners LP, El Paso Field Services and Delhi Gas Pipeline.

Mr. Bonn earned a BS degree in Agricultural Engineering from Texas A&M University and served as an officer in the United States Army before entering the energy industry. Mr. Bonn currently serves on the board of directors of the Texas Pipeline Association and the Texas Aggie Corps of Cadets Association. Mr. Bonn is a past president of the North Texas Electric Power and Natural Gas Society and served on the Executive Committee of the Marcellus Shale Coalition. Mr. Bonn is also a past board member of the New Mexico Oil & Gas Association and the National Energy Service Association.

Phillip M. Mezey

Mr. Mezey was appointed Executive Vice President of our General Partner in August 2014. Prior to this, Mr. Mezey was the co-founder of and an advisor to Blackbrush Oil and Gas LP, an oil and gas exploration and development company, and Chief Executive Officer of TexStar Midstream Services, LP. Mr. Mezey has more than 34 years of engineering and technical experience in the oil and gas industry. He served as a petroleum engineer for Texaco and manager of engineering for Delhi Gas Pipeline Corporation. Mr. Mezey was also Director of Engineering at Lewis Energy Group.

Mr. Mezey has served as founder and co-Chief Executive Officer at Blackbrush Oil and Gas, L.P. and TexStar Midstream Services, LP for over five years. Mr. Mezey received a BS degree in mechanical engineering from Syracuse University, NY and an MBA from St. Mary's University, San Antonio. He is a registered professional engineer in the states of Texas, Louisiana and Oklahoma.

J. Michael Anderson

J. Michael Anderson was appointed Senior Vice President and Chief Financial Officer of our General Partner in April 2012. Prior to joining Southcross Energy LLC, Mr. Anderson served from 2003 until 2012 as Senior Vice President and Chief Financial Officer of Exterran Holdings, Inc. and/or Exterran Partners GP LLC, the general partner of Exterran Partners, L.P., a midstream services company. Mr. Anderson also served as a member of the Board of Directors at Exterran Partners. Prior to joining Exterran Partners, Mr. Anderson served as Chief Financial Officer of Azurix Corp., a diversified water infrastructure company, and later served as the company's Chairman and Chief Executive Officer. Mr. Anderson also spent ten years at J.P. Morgan Chase & Co. in the global investment banking business where he specialized in mergers and acquisitions.

Mr. Anderson holds a BBA in finance from Texas Tech University and an MBA in finance from The Wharton School of the University of Pennsylvania.

Donna A. Henderson

Donna A. Henderson was appointed Vice President and Chief Accounting Officer of our General Partner in April 2013. From September 2011 to December 2012, Ms. Henderson was the Vice President and Chief Audit Executive of GenOn Energy, Inc., a wholesale electric generator which merged into NRG Energy. Prior to that position, Ms. Henderson served as Assistant Controller of GenOn Energy, Inc. and its predecessor companies, RRI Energy, Inc. and Reliant Energy Inc., from July 2005 to September 2011, and held various other leadership roles within the accounting department of that organization since September 2000. From 1996 to 2000, Ms. Henderson held various accounting positions with Lyondell Chemical.

Ms. Henderson began her career in Houston, Texas in 1989 with Deloitte & Touche LLP, where she worked until November 1993 when she joined KPMG LLP in Albuquerque, New Mexico, where she worked until 1995. Ms. Henderson holds a BBA in accounting from Eastern New Mexico University and is a member of the American Institute of Certified Accountants.

David W. Biegler

David W. Biegler has served as Chairman of the board of directors of our General Partner since August 2011. Mr. Biegler served as Chairman of the board of directors and Chief Executive Officer of our General Partner from August 2011 to December 2014. Mr. Biegler also served as President of our General Partner from October 2012 to March 2014. Since July 2009, Mr. Biegler served as chairman of the board of directors and chief executive officer of Southcross Energy LLC.

Mr. Biegler has more than 48 years of experience in the energy industry, having held various management positions in upstream, midstream, downstream, electric generation and oilfield services companies. From 2004 until 2012, Mr. Biegler served as chairman and chief executive officer of Estrella Energy LP, an entity formed for the purpose of acquiring midstream companies, which was a founding investor in our predecessor.

From 2002 to 2004, Mr. Biegler was the chairman of the board of Regency Gas Services, a midstream company that he co-founded and that was ultimately sold to a private equity firm. Mr. Biegler retired as vice chairman of the board of TXU Corp. (now Energy Future Holdings Corp.) in 2001, a position he assumed earlier that year. From 1997 to 2001, he served as president and chief operating officer of TXU Corp., the result of a merger between Texas Utilities and ENSERCH Corp. From 1966 to 1997, Mr. Biegler held various management positions at ENSERCH Corp. and its upstream, midstream, downstream and oilfield field services subsidiaries, including as ENSERCH's chairman, president and chief executive officer from 1994 to 1997.

Mr. Biegler serves as a director of Southwest Airlines Co., Trinity Industries, Inc. and Austin Industries. He previously served as a director of Dynegy, Inc., Guaranty Financial Group, and Animal Health International, Inc. Mr. Biegler received a bachelor's degree in physics from St. Mary's University, San Antonio, and is a graduate of Harvard University's advanced management program. He has served as a member of the National Petroleum Council and as the chairman of the American Gas Association, the Southern Gas Association, the American Gas Foundation and the Texas Pipeline Association.

Mr. Biegler was selected to serve as Chairman for a two-year term or until his earlier death or resignation by the majority of the directors, as a result of contractual arrangements entered into in connection with the Holdings Transaction.

Jon M. Biotti

Mr. Biotti has served as a director of our General Partner since April 2012. In addition, Mr. Biotti serves as the Chairman of the Compensation Committee of the board of directors of our General Partner. Mr. Biotti is a Managing Director of Charlesbank, which he joined in 1998. Mr. Biotti serves as a director of Blueknight Energy Partners G.P., L.L.C., the General Partner of Blueknight Energy Partners, L.P., a publicly traded master limited partnership that provides integrated terminalling, storage, processing, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and asphalt products. Mr. Biotti serves on the board of directors of several privately held Charlesbank portfolio companies. Mr. Biotti was also a board member of Regency Gas Services, representing Charlesbank which was Regency's founding equity investor. Educated at Harvard University, Mr. Biotti received a BA in government and sociology, an MBA and an MA in public administration.

Mr. Biotti serves as the director designee of Charlesbank, one of our Sponsors, as a result of contractual arrangements entered into in connection with the Holdings Transaction. In addition to his affiliation with Charlesbank, Mr. Biotti was selected to serve as a director due to his knowledge of the energy industry and his financial and business expertise.

Jason Downie

Mr. Downie was appointed to the board of directors of our General Partner in August 2014. Mr. Downie has over 19 years of investment experience and co-founded Tailwater in January 2013. At Tailwater, Mr. Downie's primary responsibilities include deal sourcing, transaction execution and monitoring of portfolio companies as well as executive leadership of Tailwater. Prior to co-founding Tailwater, Mr. Downie was a partner with HM Capital Partners, a private equity firm, from August 2000 to December 2012 and served on its investment committee. Mr. Downie joined HM Capital in August 2000 from Rice Sangalis Toole and Wilson, a mezzanine private equity firm, where he was an associate, from June 1999 to August 2000. Prior to Rice Sangalis Toole and Wilson, Mr. Downie was an associate in the equity trading group with Donaldson, Lufkin & Jenrette, responsible for energy and transportation. Mr. Downie currently serves as a director of TW SWD & Solids Holdco LP, Pivotal Petroleum Partners LP, TSL Holdings I LP, Southcross Holdings GP LLC, Align Midstream Partners LP and Petro Waste Environmental. Mr. Downie earned his BBA and MBA from the University of Texas at Austin.

Mr. Downie serves as the director designee of Tailwater, one of our Sponsors, as a result of contractual arrangements entered into in connection with the Holdings Transaction. In addition to his affiliation with Tailwater, Mr. Downie was selected to serve as a director due to, his knowledge of the energy industry and his financial and business expertise.

Wallace Henderson

Mr. Henderson was appointed to the board of directors of our General Partner in August 2014. Mr. Henderson has over 24 years of energy investment experience. He is currently a Managing Director and senior member of EIG's investment team where he oversees the firm's global investment activities in midstream oil and gas. Prior to joining EIG, Mr. Henderson was a senior financial consultant to Coskata, Inc., an energy technology company, from May 2009 until May 2011, when he joined EIG. Mr. Henderson also spent five years with UBS where he ran the firm's New York-based energy group and led capital raising and advisory assignments for a wide range of energy companies and sponsors including EIG. Prior to his role with UBS, Mr. Henderson was an energy investment banker at Credit Suisse for 18 years where he specialized in oil and gas project finance and corporate capital raising and M&A for large US and Latin American oil companies. Mr. Henderson received his BA in economics from Kenyon College and his MBA from Columbia University.

Mr. Henderson serves as the director designee of EIG, one of our Sponsors, as a result of contractual arrangements entered into in connection with the Holdings Transaction. In addition to his affiliation with EIG, Mr. Henderson was selected to serve as a director on the board due to his knowledge of the energy industry and his financial and business expertise.

Jerry W. Pinkerton

Jerry W. Pinkerton was appointed as an independent member of the board of directors of our General Partner in April 2012. In addition, Mr. Pinkerton serves as Chairman of the Audit Committee and Chairman of the Conflicts Committee of the board of directors of our General Partner. With respect to the Audit Committee, Mr. Pinkerton qualifies as an "audit committee financial expert." Mr. Pinkerton has over 52 years of management, finance and accounting experience and has held various positions in several publicly traded companies. Mr. Pinkerton has served on the board of directors and as chairman of the audit committee of the general partner of Holly Energy Partners, L.P., a publicly traded master limited partnership that owns and operates petroleum product and crude oil pipeline and terminal, tankage and loading rack facilities, since July 2004. From December 2000 to December 2003, Mr. Pinkerton served as a consultant to TXU Corp. (now Energy Future Holdings Corp.), and, from August 1997 to December 2000, he served as Controller of TXU Corp. and its U.S. subsidiaries. From August 1988 until its merger with TXU Corp. in August 1997, Mr. Pinkerton served as the Vice President and Chief Accounting Officer of ENSERCH Corporation. Prior to joining ENSERCH in August 1988, Mr. Pinkerton was employed for 26 years as an auditor by Deloitte Haskins & Sells, a predecessor firm of Deloitte & Touche, LLP, including 15 years as an audit partner. From May 2008 to June 2011, Mr. Pinkerton also served on the board of directors of Animal Health International, Inc., an animal health distribution company, where he also served as chairman of its audit committee. Mr. Pinkerton received his BBA degree in Accounting from The University of North Texas.

Mr. Pinkerton serves as an independent director designee of our Sponsors as a result of contractual arrangements entered into in connection with the Holdings Transaction. He was appointed due to his audit, accounting and financial reporting expertise and knowledge that qualifies him as a financial expert for his role as the chairman of the Audit Committee. Due to his executive managerial experience with public companies and public accounting firms and his prior board service, including audit committee experience, Mr. Pinkerton possesses business and management expertise and a broad range of expertise and knowledge of board committee functions.

Ronald G. Steinhart

Ronald G. Steinhart was elected as an independent member of the board of directors of our General Partner in January 2013. In addition, Mr. Steinhart serves as a member of the Audit Committee and the Compensation Committee of the board of directors of our General Partner. With respect to the Audit Committee, Mr. Steinhart qualifies as an "audit committee financial expert." Mr. Steinhart retired in 2000 as Chairman and Chief Executive Officer of the Commercial Banking Group of Bank One Corporation (commercial banking), a position he had held since 1996. He has over 36 years of experience in the financial services industry. He led a group of investors that established Team Bank (commercial banking) in 1988 and served as its Chairman and Chief Executive Officer until it merged with Bank One Texas in 1992. He was President and Chief Operating Officer of Bank One Texas through 1996. He is also a former President and Chief Operating Officer of InterFirst Corporation (commercial bank holding company), prior to which he teamed with investors to charter or purchase six other banks. He is also a current director of Penske Automotive Group, Inc. During the last five years, Mr. Steinhart has been a director of Animal Health International, Inc., Susser Holdings Corporation, and Texas Industries Inc., and has been a trustee of the MFS/Compass Group of mutual funds. Mr. Steinhart is an Advisory Board Member of the McCombs School of Business at the University of Texas at Austin. Among the civic positions in which he has served are Chairman of the Board of Trustees of the Teacher Retirement System of Texas, Chairman of the Housing Authority of the City of Dallas, Chairman of the United Way of Metropolitan Dallas, President of the Federal Advisory Council of the Federal Reserve System, Chairman of the Dallas Citizens Council and Regent of the Lamar University System. Mr. Steinhart received his BBA in accounting and his MBA in Finance from the University of Texas in Austin.

Mr. Steinhart serves as an independent director designee of our Sponsors as a result of contractual arrangements entered into in connection with the Holdings Transaction. He was appointed due to his management experience, accounting and financial expertise and knowledge. Due to his executive managerial experience and his prior board service, Mr. Steinhart possesses business and management expertise and a broad range of expertise and knowledge of board committee functions.

Bruce A. Williamson

Bruce A. Williamson was elected as an independent member of the board of directors of our General Partner in April 2013. In addition, Mr. Williamson serves as a member of the Audit Committee, Compensation Committee and Conflicts Committee of the board of directors of our General Partner. Mr. Williamson is currently the President and Chief Executive Officer and director of Cleco Corporation, an energy services company, and was the Chairman, President and Chief Executive Officer at Dynegy, Inc., an electric utility company, from 2002 through 2011. Prior to his role at Dynegy, Inc., Mr. Williamson was the President and Chief Executive Officer at Duke Energy Global Markets. Prior to Duke, Mr. Williamson was Senior Vice President Finance at PanEnergy and also worked for Shell Oil Company for 14 years in exploration and production in the United States and internationally. Mr. Williamson currently serves on the Board of Directors of Questar Corporation, an integrated natural gas company. Mr. Williamson received his BS degree in finance from the University of Montana, and his MBA from the University of Houston.

Mr. Williamson serves as an independent director designee of our Sponsors as a result of contractual arrangements entered into in connection with the Holdings Transaction. He was appointed due to his extensive expertise in the energy industry.

Code of Ethics, Corporate Governance Guidelines and Board Committee Charters

Our General Partner has adopted a Code of Business Conduct and Ethics, which applies to our General Partner's directors, officers and employees. A waiver of the Code of Business Conduct and Ethics for any director or executive officer of our General Partner may be granted only by the Audit Committee, and such committee will report any such waiver to the board of directors of our General Partner. A waiver of the Code of Business Conduct and Ethics for other officers or employees may be granted only by our Chief Executive Officer, who will thereafter report any such waiver to the Audit Committee. The board of directors of our General Partner has also adopted Corporate Governance Guidelines, which outline the important policies and practices regarding our governance. Jerry W. Pinkerton serves as the lead director, as such term is used in the Corporate Governance Guidelines.

We make available free of charge, within the "Investors" section of our website at *www.southcrossenergy.com*, and in print to any unitholder who so requests, our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Audit Committee Charter and Compensation Committee Charter. Requests for print copies may be directed to investorrelations@southcrossenergy.com or to: Investor Relations, Southcross Energy Partners, L.P., 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201, or telephone (214) 979-3720. We will post on our website all waivers to or amendments of the Code of Business Conduct and Ethics, that are required to be disclosed by applicable law and the NYSE's Corporate Governance Listing Standards. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Section 16(a) Beneficial Ownership Reporting Compliance

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

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that, except as set forth in the following, all reporting obligations of our General Partner's officers, directors and greater than 10% unitholders under Section 16(a) were satisfied during the year ended December 31, 2014. Forms 4 reporting the grant of phantom units under the LTIP were filed late for John E. Bonn, Ronald G. Steinhart, Jerry W. Pinkerton and Bruce A. Williamson on April 4, 2014. A Form 4 for vesting of phantom units under the LTIP was filed late for W. Corey Lothamer on April 3, 2014. Forms 4 reporting the sale of a small number of common units in connection with account transfer fees were filed late for two transactions for W. Corey Lothamer and one transaction for Ronald J. Barcroft on September 9, 2014. The phantom units awarded to Mr. Williamson as part of the Non-Employee Director Compensation Arrangement and Non-Employee Director Deferred Compensation Plan for his cash compensation and distribution equivalent rights were not reported in 2014. A Form 3 for EIG Asset Management, LLC was filed late on August 15, 2014 after it obtained its EDGAR codes.

Item 11. Executive Compensation

Executive Compensation Discussion

Overview of our Executive Compensation Program

This executive compensation discussion describes the compensation policies, programs, material components and decisions of the compensation committee of the board of directors of our General Partner (the "Compensation Committee") with respect to our General Partner's executive officers, including the following individuals who are referred to as our "Named Executive Officers":

- David W. Biegler, Chairman;
- John E. Bonn, President and Chief Executive Officer;
- J. Michael Anderson, Senior Vice President and Chief Financial Officer; and
- Phillip M. Mezey, Executive Vice President, Business Development

Our compensation practices and programs generally are designed to attract, retain and motivate exceptional leaders and structured to align compensation with our overall performance, including growth in distributions to unitholders. The compensation practices and programs have been implemented to promote achievement of short-term and long-term business objectives consistent with our strategic plans and are applied to reward performance. To accomplish these objectives, our compensation program consists of the following components: (i) base salary, designed to compensate executive officers for work performed during the fiscal year; (ii) short-term incentive compensation, designed to reward executive officers for our yearly performance and for performance specific to an executive officer's area of responsibility; (iii) long-term incentive compensation in the form of equity awards, meant to align the interests of our executive officers, including our Named Executive Officers, with our long-term performance; and (iv) certain benefits, perquisites, retirement, severance and change in control arrangements.

Our General Partner, under the direction of its board of directors, is responsible for managing our operations and employs all of the employees that operate our business. We reimburse our General Partner, generally on a dollar-for-dollar basis, for the compensation attributable to the work performed on our behalf by its employees for work performed for us. On December 31, 2014, our General Partner had 314 employees who provided direct support to our operations. Certain of those employees provide management, administrative, operational and workforce related services to our affiliates, including Holdings, which owns 100% of our General Partner, and an affiliate of two of our Sponsors.

References in this report to Named Executive Officers, executive officers, other officers, directors and employees refer to the Named Executive Officers, executive officers, other officers, directors and employees of our General Partner.

Role of the Compensation Committee and Management

Our General Partner is responsible for the management of us. The Compensation Committee is appointed by the board of directors of our General Partner to assist the board of directors in discharging its responsibilities relating to overall compensation matters, including, without limitation, matters relating to compensation programs for our directors and executive officers. The Compensation Committee is directly responsible for our General Partner's compensation programs, which include programs that are designed specifically for our executive officers, including our Named Executive Officers.

The Compensation Committee has overall responsibility for evaluating and approving the compensation plans, policies and programs of our General Partner. To that end, the Compensation Committee has the responsibility, power and authority to set the compensation of executive officers, determine grant awards under and administer our General Partner's equity compensation plans, and assume responsibility for all matters related to the foregoing. The Compensation Committee is charged, among other things, with the responsibility of reviewing the executive officer compensation policies and practices for (i) adherence to our compensation philosophy and (ii) ensuring that the total compensation paid to our executive officers is fair, reasonable and competitive. These compensation programs for executive officers consist of base salary, annual incentive bonus awards and awards under our 2012 Long-Term Incentive Plan ("LTIP") typically in the form of equity-based restricted units and phantom units, as well as other customary employment benefits. Total compensation of executive officers and the relative emphasis of our main components of compensation are reviewed at least on an annual basis by the Compensation Committee, which then makes recommendations to the board of directors of our General Partner for its approval.

It is the practice of the Compensation Committee to meet in person or by conference call at least once a year for a number of purposes. These include (i) assessing the performance of the Chief Executive Officer and other executive officers with respect to our results for the preceding year, (ii) establishing compensation levels for each executive officer for the ensuing year, (iii) determining the amount of the annual bonus pool approved by the board of directors of our General Partner to be paid to the executive officers, after taking into account both the target bonus levels established for those executive officers at the outset of the preceding year and the foregoing performance factors and (iv) determining equity awards under the LTIP for executive officers and other key employees. Our Chief Executive Officer participates in the process of allocating our bonus pool and makes recommendations to the Compensation Committee regarding the amount of bonuses and other compensation paid to executive officers, other than to the Chief Executive Officer.

Compensation Philosophy and Objectives

The principal objective of our compensation program is to attract and retain, as executive officers and employees, individuals of demonstrated competence, experience and leadership in our industry and in those professions required by our business who share our business aspirations, values, ethics and culture.

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

- to encourage creation of unitholder value through sustainable earnings and cash available for distribution;
- to reward participants for value creation commensurate with competitive industry standards;

- to provide a significant percentage of total compensation that is “at-risk” or variable;
- to encourage significant equity ownership to align the interests of executive officers and key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship and employee pay.

We also strive to achieve a fair balance between the compensation rewards that we perceive necessary to remain competitive in the marketplace and fundamental fairness to our unitholders, taking into account the return on their investment.

In measuring the contributions of our executive officers to the performance of us for 2014, the Compensation Committee considered and utilized the following financial and operating performance factors:

- Adjusted EBITDA reported by us;
- completion of a business combination, acquisition or transaction to enhance scale, stability and access to capital;
- costs, completion dates and operational milestones associated with the execution of our organic growth plans;
- our capital expenditures and operating expenses; and
- success in executing contracts that we anticipate will result in increased earnings and distributable cash for us.

Compensation Methodology

The Compensation Committee intends to review annually our executive compensation program in total and each element of compensation specifically. The Compensation Committee intends to include the following in its periodic review of our executive compensation program: (i) an analysis of the compensation practices of other companies in our industry; (ii) the competitive market for executive talent; (iii) the evolving demands of our business; (iv) specific challenges that we may face; and (v) individual contributions to us. The Compensation Committee will recommend to the board of directors of our General Partner adjustments to the overall executive compensation program, and to its individual components, as the Compensation Committee determines necessary to achieve our goals and comply with the Compensation Committee’s compensation philosophy. The Compensation Committee utilizes compensation consultants periodically to assist in its review of, and to provide input regarding, our compensation program and its elements.

Actual compensation decisions for individual officers are the result of the Compensation Committee’s subjective analysis of a number of factors, including the individual officer’s experience, skills or tenure with us and changes to the individual’s position. Each executive’s current and prior compensation is considered in setting future compensation. The amount of each executive’s current compensation is considered as a base-line against which the Compensation Committee makes determinations as to whether adjustments are necessary to retain the executive in light of competition or in order to provide continuing performance incentives. Thus, the Compensation Committee’s determinations regarding compensation are the result of the exercise of judgment based on all reasonably available information and, to that extent, are discretionary. The Compensation Committee may use its discretion to adjust any of the components of compensation to achieve our goal of attracting and retaining individuals with the skills necessary to execute our business strategy and to develop and grow our business.

Elements of our Compensation Programs

Compensation for our Named Executive Officers consists primarily of the elements, and their corresponding objectives, identified in the following table:

Compensation Element	Characteristics	Primary Objectives
Base salary	Fixed annual cash compensation. Salaries may be increased periodically based on performance or other factors.	Recognize performance of job responsibilities and attract and retain individuals with superior talent.
Annual performance-based compensation	Performance-related annual cash incentives earned based on financial and other objectives. For 2014 performance, no such cash awards were made.	Promote near-term performance objectives and reward individual contributions for the achievement of those objectives.
Long-term equity participation	Equity awards purchased or granted subject to time and/or performance based vesting restrictions intended to align indirect ownership interests of Named Executive Officers with unitholder interests.	Emphasize long-term performance objectives, encourage the maximization of unitholder value and retain key executives by providing an opportunity to participate in our ownership. Vesting restrictions are designed to facilitate Named Executive Officer retention and to provide continuing performance incentives.
Health and welfare benefits	Health and welfare benefits (medical, dental, vision, disability insurance and life insurance) are available for Named Executive Officers, our executive officers and all other regular full-time employees.	Provide benefits to meet the health and wellness needs of our Named Executive Officer, executive officers and other employees, and their families.
Retirement savings 401(k) plan	Qualified 401(k) retirement plan benefits are available for our Named Executive Officers, other executive officers, and all other regular full-time employees. For 2014, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 6% of the employee's eligible compensation, subject to the annual maximum contribution limit imposed by the Internal Revenue Service.	Provide an opportunity for tax-efficient savings.
Severance and change in control benefits	Severance agreements provide for base salary and benefit continuation in the event of certain terminations of employment. A portion of our Named Executive Officers' equity incentives are subject to accelerated change in control vesting.	Encourage the continued attention and dedication of our Named Executive Officers and focus their attention when considering strategic alternatives.

Compensation Components and Analysis

Base Salary. We believe that executive officer base salaries should be competitive with salaries for executive officers in similar positions with similar responsibilities in our marketplace.

The base salaries for our Named Executive Officers are set forth in the following table:

Name and Principal Position	Base Salary
David W. Biegler (1) Chairman	$200,000
John E. Bonn (2) President and Chief Executive Officer	$450,000
J. Michael Anderson (3) Senior Vice President and Chief Financial Officer	$325,000
Phillip M. Mezey (4) Executive Vice President, Business Development	$325,000

(1) In March 2014, Mr. Biegler's base salary was increased from $400,000 to $425,000, and in September 2014, Mr. Biegler's base salary was increased to $500,000, to bring his base salary closer to competitive levels in our industry. In January 2015, the base salary of Mr. Biegler was decreased to $200,000 in connection with his stepping down as our Chief Executive Officer.

(2) In January 2015, Mr. Bonn's base salary was increased from $351,000 to $450,000 to reflect his election as our Chief Executive Officer.

(3) In March 2014, Mr. Anderson's base salary was increased from $300,000 to $325,000 to bring his base salary closer to competitive levels in our industry.

(4) Mr. Mezey joined our General Partner in August 2014 in connection with the consummation of the Holdings Transaction and the TexStar Rich Gas System Transaction. In September 2014, Mr. Mezey's base salary was increased from $250,000 to $325,000 to bring his base salary closer to competitive levels in our industry.

Going forward, base salaries for our Named Executive Officers will continue to be reviewed periodically by the Compensation Committee, with adjustments expected to be made generally in accordance with the considerations described above and to maintain base salaries at competitive levels.

Annual Performance-Based Compensation. Each of our Named Executive Officers participates in an incentive bonus compensation program under which incentive awards are determined annually.

Prior to 2013, annual incentive bonuses for our executive officers were determined based on the achievement of pre-established financial and operational performance criteria, including our level of achievement against a range of total Adjusted EBITDA targets. In 2013, we determined not to establish formal Adjusted EBITDA targets or other financial and operational performance measures with respect to our 2013 annual incentive compensation program. Instead, we determined that 2013 annual incentive bonus awards for our Named Executive Officers would be determined by the board of directors of our General Partner in its discretion following the completion of the 2013 fiscal year, based upon factors such as the operational performance of newly acquired assets, capital expenditure and operating expense performance, development of growth projects, increase in new gas supply contracts and each individual's contributions to our overall success during the year.

For 2014, the board of directors of our General Partner determined not to award annual incentive bonuses to our Named Executive Officers.

This determination is not necessarily reflective of the performance of our Named Executive Officers in 2014. The current view of the Compensation Committee is that, given the current stage of the Partnership's growth and operational performance, it may better align the incentives of our Named Executive Officers with our unitholders to grant increased LTIP awards in lieu of annual cash bonus awards when determining total compensation.

Long-Term Equity Participation. Please see the sections following our Summary Compensation Table (as defined below) for discussion regarding the long-term equity compensation granted to our Named Executive Officers.

Benefit Plans, Perquisites and Retirement. We provide our executive officers, including our Named Executive Officers, with a standard complement of health and retirement benefits under the same plans as all other employees, including medical, dental and vision benefits, disability and life insurance coverage, and a defined contribution plan that is tax-qualified under Section 401(k) of the Internal Revenue Code (the "401(k) Plan"). We believe that our health benefits provide stability to our Named Executive Officers, thus enabling them to better focus on their work responsibilities, while our 401(k) Plan provides a vehicle for tax-preferred retirement savings with additional compensation in the form of an employer match that adds to the overall desirability of our executive compensation package. For 2013 and 2014, we provided an employer match under our 401(k) plan equal to 100% of employee contributions up to 6% of eligible compensation, subject to the annual maximum contribution limit imposed by the Internal Revenue Service. In addition, none of our Named Executive Officers participated in any defined benefit pension plans or non-qualified deferred compensation plans.

Severance Agreements and Change in Control Provisions. We maintain severance and other compensatory agreements with some of our executive officers for a variety of reasons, including the fact that severance agreements can be an important recruiting tool in the market in which we compete for talent. Certain provisions in these agreements, such as confidentiality, non-solicitation and non-compete clauses, protect us and our unitholders after the termination of the employment relationship. We believe that it is appropriate to compensate former executives for these post-termination agreements, and that compensation helps to enhance the enforceability of these arrangements. These agreements are described in more detail below.

Recoupment Policy. Equity awards granted under the LTIP are subject to recovery, including modification and forfeiture, for certain "Act[s] of Misconduct" as defined in the LTIP. We currently do not have a recovery policy applicable to annual cash incentive bonuses, if any are awarded. The Compensation Committee will continue to evaluate the need to amend such a policy, in light of current legislative policies, and economic and market conditions.

Compensation Committee Report

The Compensation Committee issued the following report:

We have reviewed and discussed with management certain compensation discussion provisions to be included in our Annual Report on Form 10-K for the year ended December 31, 2014 to be filed pursuant to Section 13(a) of the Securities and Exchange Act of 1934 (the "Annual Report"). Based on those reviews and discussions, we recommend to the Board of Directors of the General Partner that the Executive Compensation Discussion be included in the Annual Report.

Compensation Committee

Jon M. Biotti, Chairman
Bruce A. Williamson
Ronald G. Steinhart

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2014, the Compensation Committee was comprised of Messrs. Biotti (Chairman), Williamson and Steinhart. No member of the Compensation Committee was an officer or employee of our General Partner. Mr. Biotti is affiliated with Charlesbank, which controls Southcross Energy LLC. See Part III, Item 10 and Item 13 of this report.

Summary Compensation Table

The following table (the "Summary Compensation Table") sets forth certain information with respect to the compensation paid to our Named Executive Officers for the years ended December 31, 2013 and 2014:

Name and Principal Position	Year	Salary ($)	Stock awards ($)(1)	Non-equity incentive plan compensation ($)(2)	All other compensation ($)(3)	Total ($)
David W. Biegler	2014	442,308	3,187,019	—	17,500	3,646,827
Chairman	2013	400,000	—	—	17,500	417,500
John E. Bonn (4)	2014	283,500	1,854,560	—	64,710	2,202,770
President and Chief Executive Officer	2013	—	—	—	—	—
J. Michael Anderson	2014	319,231	1,383,462	—	1,168,600	2,871,293
Senior Vice President and Chief Financial Officer	2013	294,231	460,000	72,000	17,500	843,731
Phillip M. Mezey (5)	2014	120,192	919,656		—	1,039,848
Executive Vice President, Business Development	2013	—	—	—	—	—

(1) For 2014, represents the grant date fair value of LTIP awards for Messrs. Biegler, Bonn and Anderson based on the closing price on April 1, 2014 of $17.09 and the grant date fair value of LTIP awards for Messrs. Biegler, Bonn, Anderson and Mezey based on the closing price on August 27, 2014 of $21.69. For 2013, represents the grant date fair value of Mr. Anderson's LTIP award.

(2) For 2013, represents award earned under our annual incentive bonus program for Mr. Anderson.

(3) For Messrs. Biegler, Bonn and Anderson, represents employer contributions under our 401(k) Plan. For 2014, Mr. Biegler had a 401(k) match of $17,500. For 2014, Mr. Bonn had a 401(k) match of $16,200 and reimbursement for interim living expenses of $48,510. For 2014, Mr. Anderson had a 401(k) match of $17,500 and compensation of $1,151,100 paid by Southcross Energy LLC for the settlement of its equity equivalent units. For 2013, Mr. Biegler and Mr. Anderson each had a 401(k) match of $17,500. These amounts do not include payments for distribution equivalent rights made to Messrs. Biegler, Bonn and Anderson in 2014.

(4) Mr. Bonn became employed by us in March 2014.

(5) Mr. Mezey became employed by us in August 2014 in connection with the Holdings Transaction and the TexStar Rich Gas System Transaction.

A discussion of the material compensation information disclosed in the Summary Compensation Table is set forth in the "Compensation Components and Analysis" section above and following is a discussion of other material factors necessary to understanding the total compensation afforded to our Named Executive Officers:

Southcross Energy LLC Long-Term Equity Incentive Units. In August 2009, in connection with the formation of Southcross Energy LLC, certain of our officers, including Mr. Biegler, purchased units in Southcross Energy LLC, a portion of which were incentive units. The incentive units were subject to vesting restrictions and were intended as equity incentives to promote long-term compensation objectives and provide meaningful incentives to increase unitholder value over time. Our Named Executive Officers did not receive any equity incentive units in 2014, and Mr. Biegler is the only Named Executive Officer who owns units in Southcross Energy LLC. All of Mr. Biegler's time vesting incentive units have vested.

Mr. Biegler's Southcross Energy LLC Units. Mr. Biegler's performance based vesting units are intended to motivate Mr. Biegler and to reward the financial success of Southcross Energy LLC, which is tied directly to our financial success. The units will vest, if at all, upon the occurrence of a transaction that results in Charlesbank receiving cash or liquid securities in an amount that results in Charlesbank achieving certain investment multiples and internal rates of return with respect to its investment in Southcross Energy LLC. A portion of the performance-based vesting units vest upon the occurrence of such a transaction that results in Charlesbank achieving an investment multiple reflecting a return of 2.0 times invested capital and an internal rate of return of 20%, and the remainder of such units vest cumulatively based on the occurrence of a transaction that results in Charlesbank achieving investment multiples over and above the threshold amount. The units will be fully vested upon the occurrence of a transaction that results in Charlesbank achieving an investment multiple reflecting a return of 3.5 times invested capital and an internal rate of return of 20%. Neither the consummation of our IPO nor the Holdings Transaction and the TexStar Rich Gas System Transaction constituted a liquidity event for purposes of the performance-based incentive units. See "Potential Payments Upon a Termination or Change in Control" below for a description of the circumstances under which vesting of the incentive units may be accelerated.

Mr. Anderson's Southcross Energy LLC Units. In connection with Mr. Anderson's commencement of employment in April 2012, and to provide him with meaningful incentives to increase unitholder value over time, Mr. Anderson was granted 15,000 equity equivalent units of Southcross Energy LLC. Each of these equity equivalent units was intended to be equivalent in value to one incentive unit of the type purchased from Southcross Energy LLC by Mr. Biegler and other officers previously. In connection with the Holdings Transaction, all of Mr. Anderson's 15,000 equity equivalent units vested, resulting in a payment by Southcross Energy LLC to Mr. Anderson of $1,151,100 based on a fair market value of $76.74 per unit. As of the date of this report, Mr. Anderson does not own any equity in Southcross Energy LLC.

Named Executive Officer LTIP Units. In 2014, the board of directors of our General Partner granted an aggregate 159,447 phantom units to Mr. Biegler (58,997 of which vested in connection with the Holdings Transaction), 93,323 phantom units to Mr. Bonn (36,873 of which vested in connection with the Holdings Transaction), 69,539 phantom units to Mr. Anderson (27,139 of which, along with 13,334 phantom units awarded in 2013, vested in connection with the Holdings Transaction) and 42,400 phantom units to Mr. Mezey (none of which have vested). In addition, as described below, the board of directors of our General Partner authorized future grants, to be made on March 10, 2015, of phantom units to our Named Executive Officers, if such persons remain employed as of such date (the "2015 LTIP Awards"). The 2015 LTIP Awards are not reflected in the Summary Compensation Table because they will not be awarded as compensation earned for performance in 2014. The number of phantom units to be granted as 2015 LTIP Awards, if at all, will be determined by dividing the award value (as stated in the chart below) by the closing price of our common units on March 10, 2015. All of the foregoing phantom unit awards will be made under our LTIP, which is described further below.

The 2015 LTIP Awards are as follows:

Future Grantee	**Award Value**
David W. Biegler (1)	$425,000
John E. Bonn (1)	$904,387
J. Michael Anderson (1)	$146,250
Phillip M. Mezey (1)	$230,163

(1) For Messrs. Biegler and Anderson, all of their 2015 LTIP Award, if made, will vest on the first anniversary of the grant date. For Mr. Bonn, $198,137 of his 2015 LTIP Award, if made, will vest on the first anniversary of the grant date, and the remaining portion of the award will vest in three cumulative annual installments, as discussed below. For Mr. Mezey, $67,663 of his 2015 LTIP Award, if made, will vest on the first anniversary of the grant date, and the remaining portion of the award will vest in three cumulative annual installments, as discussed below.

Except for the 2015 LTIP Awards with one-year vesting as indicated above, the phantom units awarded to our Named Executive Officers vest in three cumulative annual installments, with one-third of the units vesting on each anniversary of the grant date, subject to continued employment through the applicable vesting date. Each phantom unit granted to our Named Executive Officers in 2014 was, and the 2015 LTIP Awards (if made) will be, granted in tandem with corresponding distribution equivalent rights (which are discussed below). Generally, upon the grantee's cessation of employment, all phantom units that have not vested will be forfeited. Phantom units will vest in full upon a cessation of service due to death or disability or upon a change in control. For further information regarding phantom units, see "Summary Compensation Table—Restricted Units and Phantom Units" below.

Long-Term Incentive Plan. Under our LTIP, certain officers (including our Named Executive Officers), employees and directors are eligible to receive awards with respect to our equity interests, thereby linking the recipients' compensation directly to our performance. The description of the LTIP set forth below is a summary of the material features of the LTIP. This summary does not purport to be a complete description of all of the provisions of the LTIP.

The LTIP provides for the grant, from time to time at the discretion of the board of directors of our General Partner or the Compensation Committee, of restricted units, phantom units, unit options, distribution equivalent rights and other unit-based awards. Subject to adjustment in the event of certain transactions or changes in capitalization, an aggregate 1,750,000 common units may be delivered pursuant to awards under the LTIP. Units that are canceled or forfeited will be available for delivery pursuant to other awards. The LTIP is administered by the board of directors of our General Partner, although such administration function may be delegated to a committee (including the Compensation Committee) that may be appointed by the board of directors of our General Partner to administer the LTIP. The LTIP is designed to promote our interests, as well as the interests of our unitholders, by rewarding our directors, officers and employees for delivering desired performance results, as well as by strengthening our ability to attract, retain and motivate qualified individuals to serve as our directors, officers and employees.

Restricted Units and Phantom Units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. The administrator of the LTIP may make grants of restricted and phantom units under the LTIP that contain such terms, consistent with the LTIP, as the administrator may determine are appropriate, including the period over which restricted or phantom units will vest. The administrator of the LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change in control (as defined in the LTIP) or as otherwise described in an award agreement.

Distributions made by us with respect to awards of restricted units may be subject to the same vesting requirements as the restricted units. The administrator of the LTIP, in its discretion, may also grant tandem distribution equivalent rights with respect to phantom units. Distribution equivalent rights are rights to receive an amount, in cash, units, restricted units and/or phantom units, equal in value to the distributions made on units during the period an award remains outstanding.

Unit Options. The LTIP also permits the grant of options covering common units. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit options may be granted to such eligible individuals and with such terms as the administrator of the LTIP may determine, consistent with the LTIP; however, a unit option must have an exercise price equal to at least the fair market value of a common unit on the date of grant (except under certain circumstances).

Other Unit-Based Awards. The LTIP also permits the grant of "other unit-based awards," which are awards that, in whole or in part, are valued or based on or related to the value of a unit.

The vesting of an "other unit-based award" may be based on a participant's continued service, the achievement of performance criteria or other measures. On vesting or on a deferred basis upon specified future dates or events, an "other unit-based award" may be paid in cash and/or in units (including restricted units), as the administrator of the LTIP may determine.

Source of Common Units; Cost. Common units to be delivered with respect to awards may be newly-issued units, common units acquired by us or our General Partner in the open market, common units already owned by our General Partner or us, common units acquired by our General Partner directly from us or any other person or any combination of the foregoing. With respect to awards made to employees of our General Partner, our General Partner will be entitled to reimbursement by us for the cost incurred in acquiring such common units or, with respect to unit options, for the difference between the cost it incurs in acquiring these common units and the proceeds it receives from an optionee at the time of exercise of an option. Thus, we will bear the cost of all awards under the LTIP. If we issue new common units with respect to these awards, the total number of common units outstanding will increase, and our General Partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash by our General Partner, our General Partner will be entitled to reimbursement by us for the amount of the cash settlement.

Amendment or Termination of LTIP. The administrator of the LTIP, at its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The LTIP will automatically terminate on the tenth anniversary of the date it was initially adopted by the board of the General Partner. The administrator of the LTIP also will have the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP, provided that no change in any outstanding award may be made that would impair materially the rights of the participant without the consent of the affected participant, and/or result in taxation to the participant under the Internal Revenue Code Section 409A.

All Other Compensation. Please see the discussions above for a discussion of the base salaries, short- and long-term incentive compensation, benefits, perquisites and retirement arrangements paid or made available to our Named Executive Officers. Please also see the section below entitled "Outstanding Equity Awards at December 31, 2014" for a discussion of outstanding equity awards and the section below entitled "Potential Payments Upon a Termination or Change in Control" for a discussion of payments made upon termination of employment and certain change in control events.

Outstanding Equity Awards at December 31, 2014

Southcross Energy LLC Equity Awards. The following table provides information regarding incentive units of Southcross Energy LLC held by our Named Executive Officers as of December 31, 2014 (in thousands).

	Southcross Energy LLC Incentive Units			
Name	**Number of time-vesting units that have not vested**	**Market value of time-vesting units that have not vested**	**Number of performance-vesting units that have not vested**	**Market value of performance vesting units that have not vested**[(2)]
David W. Biegler	—	—	43,470[(1)]	3,335,888
John E. Bonn	—	—	—	—
J. Michael Anderson	—	—	—	—
Phillip M. Mezey	—	—	—	—

(1) Represents the number of unvested performance vesting incentive units purchased on August 6, 2009. The units will vest, if at all, upon Charlesbank attaining certain investment multiples, as described above, in connection with a liquidity event with respect to its investment in Southcross Energy LLC. For additional information relating to the performance vesting incentive units, see the discussion above under "Summary Compensation Table—Southcross Energy LLC Long-Term Equity Incentive Units."

(2) Amounts shown were calculated based on an estimate of the fair market value of units of $76.74 in Southcross Energy LLC on December 31, 2014.

Southcross Energy Partners, L.P. Equity Awards. The following table provides information regarding LTIP units held by our Named Executive Officers as of December 31, 2014 (in thousands):

	Southcross Energy Partners, L.P. - LTIP Units			
Name	**Number of time-vesting units that have not vested**(1)	**Fair value of time-vesting units that have not vested**(2)	**Number of performance-vesting units that have not vested**	**Fair value of performance vesting units that have not vested**
David W. Biegler	100,450	$1,597,155	—	—
John E. Bonn	56,450	$ 897,555	—	—
J. Michael Anderson	42,400	$ 674,160	—	—
Phillip M. Mezey	42,400	$ 674,160	—	—

(1) Represents the number of unvested time vesting LTIP units awarded to our Named Executive Officers on August 27, 2014, subject to the recipient's continued employment through the applicable vesting date. The units vest in three equal installments on August 27th of 2015, 2016 and 2017.

(2) Amounts were calculated based on the closing price per common unit on December 31, 2014 of $15.90.

The foregoing table does not include the 2015 LTIP Awards, which represent future grants to be made to our Named Executive Officers on March 10, 2015, if they remain employed as of such date.

Potential Payments Upon a Termination or Change in Control

Severance and Change in Control Benefits. Our Named Executive Officers are entitled to severance payments and benefits upon certain terminations of employment and, in certain cases, upon a change in control. In addition, Mr. Anderson is entitled to severance payments and benefits upon certain qualifying terminations of employment (including in connection with a change in control) and, in certain cases, upon a change in control.

Messrs. Biegler and Anderson have entered into severance agreements with our General Partner that provide for severance benefits upon certain terminations of employment. Mr. Bonn has entered into an employment agreement with our General Partner that provides for severance benefits upon certain terminations of employment. Mr. Mezey has not entered into a severance agreement with our General Partner. As described below, the severance agreements of Messrs. Biegler and Anderson are substantially similar. Also, as described further below, Mr. Anderson is entitled to a retention payment under a separate agreement if certain conditions are met in 2015.

Mr. Biegler's Severance and Change in Control Benefits. Under the severance agreement for Mr. Biegler, upon termination of his employment by us without "cause" or by executive for "good reason" (provided such termination for "good reason" occurs no more than 45 days following the last event constituting "good reason"), Mr. Biegler is entitled to receive (i) twelve months of base salary continuation and (ii) company-subsidized group health plan benefits for up to twelve months. Additionally, severance payments are conditioned upon the execution of a general release of claims and continued compliance with certain non-competition and non-solicitation restrictions for twelve months following termination.

"Cause" is defined in the severance agreement for Mr. Biegler to mean (i) his indictment for or conviction of, or entering a plea of nolo contendere, to any crime (whether or not a felony) involving dishonesty, fraud, embezzlement, breach of trust or other crime of moral turpitude, (ii) his conviction of, entering a plea of nolo contendere to, a felony (other than a traffic violation), (iii) acts by him constituting fraud or willful misconduct in connection with the his employment or service relationship, including misappropriation or embezzlement in the performance of his duties, (iv) his failure or willful refusal to perform any of his duties (other than a failure resulting from incapacity due to physical or mental illness) which is reasonably likely to result in material harm to Southcross Energy LLC or its subsidiaries, provided that such failure or refusal is not cured within 30 days of receiving written notice from Southcross Energy LLC, (v) his violation or breach of the ethics provisions of the employee handbook applicable to all employees generally, or his duty of loyalty to Southcross Energy LLC or its affiliates, (vi) his willfully or grossly negligently engaging in conduct materially injurious to Southcross Energy LLC or any of its subsidiaries or (vii) his failure or refusal to devote a majority of his "business time" to the business and affairs of Southcross Energy LLC and its subsidiaries, provided that such failure or refusal is not cured within 30 days of receiving written notice from Southcross Energy LLC. Generally, "business time" excludes time spent serving on certain corporate, charitable or civic boards or committees, or delivering lectures, fulfilling speaking engagements or teaching at educational institutions.

"Good reason" is defined in Mr. Biegler's severance agreement to mean (i) an involuntary reduction in his annual base salary, other than a reduction to which Mr. Biegler consents or that similarly affects all or substantially all management employees, (ii) a relocation, without his prior written consent, of the geographic location of his principal place of employment by more than twenty-five miles from his original principal place of employment or (iii) the failure of Southcross Energy LLC or any of its subsidiaries to pay any cash compensation (such as base salary or bonuses) to Mr. Biegler when due under the terms of any employment agreement or bonus plan in which he is entitled to participate, provided that Southcross Energy LLC has not cured such failure within 30 days of receiving written notice from Mr. Biegler.

Mr. Biegler is not entitled to any cash payments upon a change in control of us or Southcross Energy LLC. With regard to Mr. Biegler's LTIP phantom unit awards, upon certain transactions generally resulting in a change in control of our General Partner or Partnership or cessation of his services due to death or disability, any unvested phantom units will vest in full. As set forth above, 58,997 of Mr. Biegler's phantom units vested in August 2014 in connection with the Holdings Transaction. For additional information regarding the vesting of the phantom units, see the discussion under the Summary Compensation Table above.

Upon the occurrence of a liquidity event with respect to Charlesbank's investment in Southcross Energy LLC, which event may also constitute a change in control, Mr. Biegler's performance vesting incentive units may vest, depending upon the financial outcome of such transaction. For additional information regarding the vesting of the performance vesting incentive units, see the discussion under "Summary Compensation Table—Mr. Biegler's Southcross Energy LLC Units" above.

Mr. Anderson's Severance and Change in Control Benefits. Under Mr. Anderson's severance agreement, upon a termination of his employment by us without "cause" or by him for "good reason," in either case, within one year following certain transactions generally resulting in a change in control of Southcross Energy LLC, subject to his execution of a general release agreement, Mr. Anderson will also be entitled to receive (i) an amount equal to two times his annual base salary, (ii) an amount equal to two times his target annual bonus, which is 60% of his base salary, and (iii) reimbursement for the cost of group health plan benefits for eighteen months. Mr. Anderson has certain non-solicitation obligations for twelve months following his termination. The general release agreement is to include a non-solicitation provision for twelve months following termination and agreeing to continuing confidentiality obligations.

For purposes of Mr. Anderson's severance agreement, "cause" is defined to mean (i) his failure to satisfactorily perform his material duties or to devote his full time and effort to his position, (ii) his violation of any material General Partner policy (provided that such violation is not cured after receiving reasonable notice from our General Partner), (iii) his failure to follow lawful directives from our General Partner's Chief Executive Officer, President or Executive Vice President, the board of directors of our General Partner, or his direct supervisor, (iv) his negligence or material misconduct, (v) his dishonesty or fraud or (vi) his felony conviction.

In addition, "good reason" is defined in Mr. Anderson's severance agreement to mean (i) a material change in his job duties and responsibilities, (ii) a reduction in his compensation (unless the reduction similarly affects similarly situated employees) or (iii) a change in the location of his regular workplace by more than twenty-five miles.

As set forth above, all of Mr. Anderson's equity equivalent units vested in August 2014 in connection with the Holdings Transaction, resulting in a cash payment to Mr. Anderson.

With regard to Mr. Anderson's LTIP phantom unit awards, upon certain transactions generally resulting in a change in control of our General Partner or Partnership or cessation of his services due to death or disability, any unvested phantom units will vest in full. As set forth above, 40,473 of Mr. Anderson's phantom units vested in August 2014 in connection with the Holdings Transaction. For additional information regarding the vesting of the phantom units, see the discussion under the Summary Compensation Table above.

Mr. Anderson's Retention Agreement. In November 2014, Mr. Anderson entered into a retention agreement with our General Partner providing for the payment to Mr. Anderson of $325,000 after the timely filing of this report and his continued employment as of May 1, 2015 (other than by reason of an involuntary termination by the Company without cause or a resignation for good reason).

A for "cause" termination would occur under Mr. Anderson's retention agreement if (i) he fails to perform satisfactorily his material duties or to devote his full time and effort to his position, (ii) he violates any material Company policy that remains unremedied after reasonable notice to cure the violation, (iii) he fails to follow lawful directives from the Company's Chief Executive Officer, the Company's Board of Directors or his direct supervisor, (iv) his negligence or material misconduct, (v) his dishonesty or fraud or (vi) any felony conviction.

A "good reason" termination would be permitted under Mr. Anderson's retention agreement upon (i) a material reduction in his compensation unless the reduction applies to all Company employees employed at similar levels or (ii) a change in the location that he regularly works of more than 25 miles, provided that "good reason" shall not occur unless he provides to Company written notice of the existence of the permitted termination event within a period not to exceed 30 days from the initial existence of the condition stating in reasonable detail the basis for the "good reason" condition and the Company will have the opportunity for a period of 30 days from the receipt of his notice to cure the "good reason" condition described in his written notice.

Mr. Bonn's Severance and Change in Control Benefits. On March 5, 2015, our General Partner entered into an employment agreement with John E. Bonn, the President and Chief Executive Officer of our General Partner (the "Bonn Employment Agreement"). The Bonn Employment Agreement provides for an initial three-year term, unless earlier terminated. The Bonn Employment Agreement automatically extends for one year periods unless notice is given otherwise prior to the expiration of the then-current term. Mr. Bonn will receive an annual base salary of $450,000 for the first year, $500,000 for the second year and not less than $500,000 for each year thereafter, as determined by the board of directors of our General Partner. Mr. Bonn may receive an annual cash bonus based on annual performance targets in an amount determined by the board of directors of our General Partner in its discretion with a target annual bonus equal to Mr. Bonn's salary for such year. In 2015, Mr. Bonn is entitled to receive a grant of LTIP with a fair market value of $200,000 (and if made, Mr. Bonn's 2015 LTIP Award will satisfy this covenant). Mr. Bonn may also receive LTIP awards as determined by the board of directors of our General Partner. Mr. Bonn is also entitled to receive certain benefits and reimbursement of certain expenses, including relocation expenses.

Under the Bonn Employment Agreement, upon a termination of Mr. Bonn's employment by us without "cause" or by Mr. Bonn for "good reason," Mr. Bonn will be entitled to receive (i) an amount equal to two times his then-current annual base salary, (ii) an amount equal to two times his target annual bonus, (iii) an amount equal to the cost of COBRA coverage for 18 months after termination and (iv) an amount equal to $150,000 if terminated during the first year, $100,000 if terminated during the second year or $50,000 if terminated during the third year (and no additional payment if Mr. Bonn is terminated after the third year). The severance payment is subject to Mr. Bonn's execution of a general release agreement and compliance with certain restrictions.

A for "cause" termination would occur under the Bonn Employment Agreement if (i) Mr. Bonn fails to perform satisfactorily his material duties or to devote his full time and effort to his position, (ii) violates any material company policy that remains un-remedied after reasonable notice to cure the violation, (iii) fails to follow lawful directives from our Chairman or the board of directors of our General Partner, (iv) his negligence or material misconduct, (v) his fraud, embezzlement, misappropriation, material misconduct, conversion of assets or breach of fiduciary duty or (vi) any felony conviction.

A “good reason” termination would be permitted under Mr. Bonn’s employment within 90 days after the following occurs (without Mr. Bonn’s written consent): (i) Mr. Bonn is removed as Chief Executive Officer, (ii) a material diminution of his base salary or (iii) a change in the location of Mr. Bonn’s employment that requires Mr. Bonn to relocate his residence to a location more than 50 miles from Dallas, Texas.

During his employment and for one year following his termination, Mr. Bonn is subject to certain non-competition and non-solicitation provisions set forth in the Bonn Employment Agreement. Mr. Bonn is also subject to certain confidentiality provisions during and after his employment.

With regard to Mr. Bonn’s LTIP phantom unit awards, upon certain transactions generally resulting in a change in control of our General Partner or Partnership or cessation of his services due to death or disability, any unvested phantom units will vest in full. As set forth above, 36,873 of Mr. Bonn’s phantom units vested in August 2014 in connection with the Holdings Transaction. For additional information regarding the vesting of the phantom units, see the discussion under the Summary Compensation Table above.

Mr. Mezey’s Change in Control Benefits. With regard to Mr. Mezey’s LTIP phantom unit award, upon certain transactions generally resulting in a change in control of our General Partner or Partnership or cessation of his services due to death or disability, any unvested phantom units will vest in full. For additional information regarding the vesting of the phantom units, see the discussion under the Summary Compensation Table above.

Director Compensation

Officers, employees or paid consultants of our General Partner who also serve as directors do not receive additional compensation for their service as directors. Our directors who are not officers, employees or paid consultants of our General Partner receive a combination of cash and common units to be granted pursuant to the LTIP as compensation for attending meetings of our board of directors of our General Partner and any committees thereof. Specifically, directors are eligible for the following:

i. An annual retainer of $50,000, to be paid quarterly in arrears;

ii. An annual retainer of $10,000 for the Chairperson of the Audit Committee, to be paid quarterly in arrears;

iii. An annual retainer of $5,000 for the Chairperson of the Compensation Committee, to be paid quarterly in arrears;

iv. An annual retainer of $2,500 for the Chairperson of the Conflicts Committee, to be paid quarterly in arrears;

v. $1,500 for each board meeting attended (whether in person or telephonically);

vi. $1,200 for each committee (Audit, Compensation or Conflicts) meeting attended (whether attended in person or telephonically);

vii. A per diem amount for assistance with special projects, in an amount commensurate with the amount payable for attendance at Board or Committee meetings; and

viii. An annual equity grant of common units from us pursuant to the LTIP equivalent to $75,000 divided by the average of the closing daily sales price of our common units for the ten trading days immediately prior to April 1st of each year; or at the option of us, $75,000 in cash in lieu of such equity grant.

Pursuant to the Non-Employee Director Compensation Arrangement, compensation for directors who serve for only a portion of a year is pro-rated for time served. Our non-employee directors are reimbursed for certain expenses incurred for their services to us.

We have adopted the Southcross Energy Partners, L.P. Non-Employee Director Deferred Compensation Plan, pursuant to which non-employee directors of our general partner may elect on an annual basis to defer all earned cash and/or equity compensation until the director is no longer a director of our general partner. All amounts deferred will be converted into phantom units from us, which will be entitled to receive quarterly distributions from us. These quarterly distributions will also be converted to phantom units. At the conclusion of the deferral period, the accrued phantom units will be paid to the director in the form of (i) cash for deferrals of cash compensation equal to the fair market value as of such date and (ii) common units for deferrals of equity compensation. For the calendar year 2014, Mr. Williamson has elected to defer his non-employee director compensation.

Each of Messrs. Bartlett, Biotti and Davis informed us that in accordance with the internal policies of Charlesbank and the terms of the limited partnership agreements for the Charlesbank funds that have invested in Southcross Energy LLC (the "Charlesbank Fund"), that all compensation otherwise payable to any of them as a result of being a director of our General Partner should be paid as follows (i) cash compensation should be paid directly to Charlesbank and (ii) in lieu of equity compensation, any such additional compensation should be paid in cash directly to Charlesbank.

Mr. Downie informed us that in accordance with the internal policies of Tailwater and the terms of the limited partnership agreements for the Tailwater funds, all cash compensation otherwise payable to Mr. Downie as a result of being a director of our General Partner should be paid directly to an affiliate of Tailwater.

Mr. Henderson also informed us that in accordance with the internal policies of EIG and the terms of the limited partnership agreements for the EIG funds, that all compensation otherwise payable to Mr. Henderson as a result of being a director of our General Partner should be paid as follows: (i) cash compensation should be paid directly to EIG and (ii) in lieu of equity compensation, any such additional compensation should be paid directly to EIG.

Director Compensation for 2014

The following table presents the cash, equity awards and other compensation earned, paid or awarded to each of our directors during the year ended December 31, 2014:

Name	Fees earned or paid in cash	Equity awards	Total
Jon M. Biotti [(1)]	$78,100	$75,000 [(4)]	$153,100
Kim G. Davis [(1)]	$40,255	$75,000 [(4)]	$115,255
Samuel P. Bartlett [(1)]	$40,255	$75,000 [(4)]	$115,255
Jason Downie [(2)]	$27,745	$ —	$ 27,745
Wallace Henderson [(3)]	$27,745	$ —	$ 27,745
Jerry W. Pinkerton	$95,800	$75,000 [(5)]	$170,800
Ronald G. Steinhart	$77,900	$75,000 [(6)]	$152,900
Bruce A. Williamson	$91,100	$75,000 [(7)]	$166,100

(1) Directors associated with Charlesbank. In connection with the closing of the Holdings Transaction and the TexStar Rich Gas System Transaction and effective as of that date, Messrs. Bartlett and Davis resigned as directors and were replaced by Mr. Downie (as the Tailwater designee) and Mr. Henderson (as the EIG designee).

(2) Director associated with Tailwater.

(3) Director associated with EIG.

(4) In lieu of an equity grant pursuant to the LTIP received a cash payment.

(5) Mr. Pinkerton received 4,381 common units on April 1, 2014 based on a per unit price of $17.12, which is the average of the daily per unit closing price of our common units for the ten trading days immediately before April 1, 2014.

(6) Mr. Steinhart received 4,381 common units on April 1, 2014 based on a per unit price of $17.12, which is the average of the daily per unit closing price of our common units for the ten trading days immediately before April 1, 2014.

(7) Mr. Williamson received 4,381 phantom units on April 1, 2014 based on a per unit price of $17.12, which is the average of the daily per unit closing price of our common units for the ten-day trading days immediately before April 1, 2014. Pursuant to Mr. Williamson's election to defer such award in accordance with the Non-Employee Director Deferred Compensation Plan, Mr. Williamson was issued the reported phantom units. Including the phantom units granted to Mr. Williamson on April 1, 2014, Mr. Williamson has a total of 15,057 phantom units outstanding as of December 31, 2014.

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

The following table sets forth certain information regarding the beneficial ownership of our units as of March 2, 2015 by:

- each person known to us to beneficially own 5% or more of any class of our outstanding units (including any "group" as that term is used in Section 13(d)(3) of the Exchange Act;
- each of the directors and named executive officers of our General Partner; and
- all of the directors and executive officers of our General Partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders, as the case may be, or based on a review of the copies of reports furnished to us.

Our General Partner is owned 100% by Holdings. Charlesbank, EIG and Tailwater each indirectly own approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine Opportunities Fund and GE Energy Financial Services own certain additional ownership interests in Holdings as well. The general partner of Holdings is Southcross Holdings GP LLC, of which Charlesbank, EIG and Tailwater each indirectly own approximately one third. Our General Partner owns all of the general partner interests in us.

The amounts and percentage of units beneficially owned are reported on the basis of SEC regulations governing the determination of beneficial ownership of securities. Under the SEC regulations, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote, or to direct the voting, of such security, and/or "investment power," which includes the power to dispose, or to direct the disposition of, such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, a right to acquire beneficial ownership of a security within 60 days of March 2, 2015 by a person, if any, are deemed to be outstanding for computing the percentage of outstanding securities of the class by such person, but are not deemed to be outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting power and sole investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

The percentages of units beneficially owned are based on a total of 23,800,943 common units, 12,213,713 subordinated units and 15,149,636 Class B Convertible Units outstanding as of March 2, 2015.

Name and address of beneficial owner(1)	Common units beneficially owned	Percentage of common units beneficially owned	Subordinated units beneficially owned	Percentage of subordinated units beneficially owned	Class B Convertible Units beneficially owned(1)	Percentage of Class B Convertible Units beneficially owned	Percentage of total common, subordinated and Class B Convertible Units beneficially owned
Our Holding Company:							
Southcross Holdings LP(2)(3)(4)	2,116,400	8.9%	12,213,713	100.0%	15,149,636	100%	57.6%
5% Owners Not Listed Above or Below:							
Southcross Energy LLC(4)	2,116,400	8.9%	12,213,713	100.0%	15,149,636	100%	57.6%
EIG Blackbrush Holdings, LLC(5)	2,116,400	8.9%	12,213,713	100.0%	15,149,636	100%	57.6%
TW BBTS Aggregator LP(6)	2,116,400	8.9%	12,213,713	100.0%	15,149,636	100%	57.6%
Advisory Research, Inc.(7)	2,424,852	10.2%	—	—	—	—	10.2%
Neuberger Berman Group LLC(8)	5,114,039	21.5%	—	—	—	—	21.5%
Oppenheimer Funds, Inc.(9)	2,447,856	10.3%	—	—	—	—	10.3%
Directors and Named Executive Officers of Our General Partner:							
J. Michael Anderson(2)	37,216	*	—	—	—	—	*
David W. Biegler(2)	39,549	*	—	—	—	—	*
Jon M. Biotti(4)(10)	—	—	—	—	—	—	—
John E. Bonn(2)	23,112	*	—	—	—	—	*
Jason H. Downie(6)(11)	2,116,400	8.9%	12,213,713	100.0%	15,149,636	100%	57.6%
Wallace C. Henderson(12)	—	—	—	—	—	—	—
Phillip M. Mezey(2)	—	—	—	—	—	—	—
Jerry W. Pinkerton(2)	9,374	*	—	—	—	—	*
Ronald G. Steinhart(2)(13)	21,514	*	—	—	—	—	*
Bruce A. Williamson(2)(14)	7,374	*	—	—	—	—	*
All current directors and executive officers of our General Partner as a group (consisting of 11 persons)(4)(6)(11)(14)(15)	2,269,655	9.5%	12,213,713	100.0%	15,149,636	100%	57.9%

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

(1) This beneficial ownership table was prepared as of March 2, 2015. The subordinated units convert into common units on a one-for-one basis on the expiration of the Subordination Period (as defined in the Partnership Agreement). The Class B Convertible Units convert into common units at the Class B Conversion Rate (as defined in our Partnership Agreement), on the Class B Conversion Date (as defined in the Partnership Agreement). Because such subordinated units and Class B Convertible Units were acquired in connection with transactions having the purpose or effect of changing or influencing the control of us, such Class B Convertible Units and subordinated units are considered converted for purposes of the calculations of the amounts noted under Rule 13d-3(d)(1)(i) of the Securities Exchange Act of 1934, as amended. Pursuant to Rule 13d-3(d)(1)(i), the subordinated units and Class B Convertible Units are deemed outstanding for computing the percentage of the class owned by such beneficial owner, but not deemed to be outstanding for the purpose of computing the percentage of the class for any other person. The beneficial ownership reported for the Class B Convertible Units includes additional Class B Convertible Units issued in kind as distributions in the third and fourth quarters of 2014.

(2) The address for this person or entity is 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201.

(3) Holdings owns 100% of our General Partner, and through its wholly-owned subsidiaries, owns 2,116,400 of our common units, 12,213,713 of our subordinated units and 15,149,636 of our Class B Convertible Units.

(4) Based on a Schedule 13D filed with the SEC on August 14, 2014. The filing was made jointly by Southcross Energy LLC, Charlesbank Capital Partners, LLC, Southcross Holdings GP LLC, Holdings, Southcross Holdings Guarantor GP LLC, Southcross Holdings Guarantor LP, Southcross Holdings Borrower GP LLC and Southcross Holdings Borrower LP. Each party to the Schedule 13D shares

voting and dispositive power. Jon Biotti, a director of our General Partner, is a managing director of Charlesbank Capital Partners, LLC, the investment adviser to the Charlesbank funds. Mr. Biotti disclaims beneficial interest in our common units, subordinated units and Class B Convertible Units, except to the extent of his pecuniary interest therein. The address for each party to the Schedule 13D, except for Charlesbank Capital Partners, LLC, is 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201. The address for Charlesbank Capital Partners, LLC is 200 Clarendon Street, 54th Floor, Boston, Massachusetts 02116.

(5) Based on a Schedule 13D filed with the SEC on August 14, 2014, as amended by a Schedule 13D/A filed with the SEC on December 8, 2014. The filing was made jointly by EIG BlackBrush Holdings, LLC, EIG Management Company, LLC, EIG Asset Management, LLC, EIG, The R. Blair Thomas 2010 Irrevocable Trust and R. Blair Thomas. Each party to the Schedule 13D, as amended, shares voting and dispositive power. The address for each party to the Schedule 13D, as amended, is 1700 Pennsylvania Ave. NW, Suite 800, Washington, D.C. 20006.

(6) Based on a Schedule 13D filed with the SEC on August 14, 2014, as amended by a Schedule 13D/A filed with the SEC on December 8, 2014. The filing was made jointly by TW BBTS Aggregator LP, BB-II Holdco LP, TW/LM GP Sub, LLC, Tailwater Energy Fund I LP, TW GP EF-I, LP, TW GP EF-I GP, LLC, Tailwater, Jason H. Downie and Edward Herring. Each party to the Schedule 13D, as amended, shares voting and dispositive power. Based on the relationship of Jason H. Downie to Holdings, Downie, a director of our General Partner, may be deemed to indirectly beneficially own the common units, subordinated units and Class B Convertible Units held by Holdings. The address for each party to the Schedule 13D, as amended, is 300 Crescent Court, Suite 200, Dallas, Texas 75201.

(7) Based on a Schedule 13G/A filed with the SEC on February 17, 2015. The filing was made jointly by Piper Jaffray Companies (“PJA”) and Advisory Research, Inc. (“ARI”) and reflects that PJA may be deemed to be the beneficial owner of the common units through control of ARI, its wholly-owned subsidiary PJA disclaims beneficial interest in our common units and PJA and ARI each have sole voting power over 1,626,357 common units, sole dispositive power over 1,656,692 common units and shared voting power and shared dispositive power over 768,160 common units. The address for PJA is 800 Nicollet Mall, Suite 800, Minneapolis, Minnesota 55402 and the address for ARI is 180 North Stetson, Chicago, Illinois 60601.

(8) Based on a Schedule 13G/A filed with the SEC on February 11, 2015. The filing was made jointly by Neuberger Berman Group LLC (“NB Group”), Neuberger Berman LLC (“NB”), Neuberger Berman Management LLC (“NB Management”) and Nueberger Berman MLP Income Fund Inc. (“NB Fund”). The filing reflects that NB Group and NB each share voting power over 4,855,687 common units and share dispositive power over 5,114,039 common units. The filing also reflects that NB Management shares voting power over 1,861,668 common units, shares dispositive power over 1,861,668 common units and has beneficial ownership of 1,861,668 common units. The filing also reflects that NB Fund shares voting power over 1,860,068 common units, shares dispositive over 1,860,068 common units and has beneficial ownership of 1,860,068 common units. Each of NB Group, NB and NB Management disclaims beneficial ownership of the units covered in the Schedule 13G/A. The address for each party to the Schedule 13G, as amended, is 605 Third Avenue, New York, New York 10158.

(9) Based on a Schedule 13G/A filed with the SEC on February 9, 2015. The filing was made jointly by OppenheimerFunds, Inc. (“OF”) and Oppenheimer SteelPath MLP Income Fund (“OSP”). The filing reflects that OF has shared voting power and shared dispositive power over 2,447,856 common units and beneficial ownership of 2,447,856 common units. The filing also reflects that OSP has sole voting power and shared dispositive power over 2,414,581 common units and beneficial ownership of 2,414,581. OF disclaims beneficial ownership of the 2,447,856 common units, which includes the ownership of OSP. The address for OF is Two World Financial Center, 225 Liberty Street, New York, New York 10281 and the address for OSP is 6803 S. Tucson Way, Centennial, Colorado 80112.

(10) The address for Mr. Biotti is 200 Clarendon Street, 54th Floor, Boston, Massachusetts 02116.

(11) Mr. Downie owns no units directly. Includes 2,116,400 common units, 12,213,713 subordinated units and 15,149,636 Class B Convertible Units indirectly owned by Holdings. Based on the relationship of Mr. Downie to Holdings, Mr. Downie may be deemed to indirectly beneficially own the securities held by Holdings. Mr. Downie disclaims beneficial ownership of the securities reported, except to the extent of Mr. Downie’s indirect pecuniary interest.

(12) The address for Mr. Henderson is 1700 Pennsylvania Ave. NW, Suite 800, Washington, D.C. 20006.

(13) Includes 11,514 common units owned directly by Mr. Steinhart. Also includes 2,500 common units owned by each of two of Mr. Steinhart’s sons and 1,000 common units owned by each of five trusts established for the benefit of Mr. Steinhart’s grandchildren, over which Mr. Steinhart shares voting and dispositive power. Mr. Steinhart has no pecuniary interest in, and disclaims any ownership of, such common units that are not owned by Mr. Steinhart directly.

(14) Represents phantom units per the Non-Employee Director Deferred Compensation Plan which Mr. Williamson has the right to acquire common units within 30 days on termination of his services. Mr. Williamson has elected to defer all earned compensation under the Non-Employee Director Deferred Compensation Plan until he is no longer a director of our General Partner. In accordance with the Non-Employee Director Deferred Compensation Plan, Mr. Williamson has a total of 15,057 phantom units, 7,683 of which will be settled in cash equal to the fair market value of our common units on the date of termination of Mr. Williamson’s services (and which are not included in the table).

(15) Does not include any unvested phantom units granted to such directors and executive officers under the LTIP.

Securities Authorized for Issuance Under Equity Compensation Plan[(1)]

We have one compensation plan under which our common units are authorized for issuance, the LTIP. This equity compensation plan was approved by our unitholders. The following table sets forth certain information relating to the LTIP as of December 31, 2014:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by securities holders	470,750	—	900,284
Equity compensation plans not approved by security holders	—	—	—
Total	470,750	$—	900,284

(1) See Note 14 to our consolidated financial statements for more information. No value is shown in column (b) of the table because the phantom units do not have an exercise price.

Item 13. Certain Relationships and Related Transactions, and Director Independence

As of March 2, 2015, Holdings owns 2,116,400 common units, 12,213,713 subordinated units and 15,149,636 Class B Convertible Units, representing a combined 57.6% limited partner interest in us. In addition, Holdings owns and controls our General Partner, which owns a 2.0% General Partner interest in us and all of our incentive distribution rights.

The following table summarizes the distributions and payments owed by us to our General Partner and its affiliates in connection with our ongoing operations and liquidation. Certain of these distributions and payments were determined among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage

Distributions to our General Partner and its affiliates	We generally make cash distributions (except with respect to our Class B Convertible Units, which are paid in Class B PIK Units) of 98.0% to our unitholders pro rata (including to Holdings, as the holder of a 57.6% limited partnership interest in us) and 2.0% to our General Partner, assuming our General Partner makes any capital contributions necessary to maintain its 2.0% general partner interest in us. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, our General Partner is entitled to increasing percentages of the distributions, up to 48.0% of the distributions above the highest target distribution level in connection with its incentive distribution rights.
Payments to our General Partner and its affiliates	Our General Partner does not receive a management fee or other compensation for its management of us. However, our General Partner and its affiliates are entitled to reimbursement for all expenses incurred on our behalf, including, among other items, compensation expense for all employees required to manage and operate our business. Our Partnership Agreement provides that our General Partner will determine the amount of these reimbursed expenses. In addition, as described below, these

	employees provide services to affiliated entities, including Holdings, and the expenses for these services are allocated by the board of directors of our General Partner.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case, for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, our partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Southcross Energy Partners GP, LLC (our General Partner)

Our General Partner does not receive a management fee or other compensation for its management of us. However, our General Partner and its affiliates are entitled to reimbursements for all expenses incurred on our behalf, including, among other items, compensation expense for all employees required to manage and operate our business. During the year ended December 31, 2014, we incurred expenses related to these reimbursements, which are reflected in operating expenses in our consolidated statements of operations.

Acquisition of TexStar Rich Gas System

On August 4, 2014, we completed our approximately $450.0 million acquisition of the TexStar Rich Gas System in connection with consummation of the Holdings Transaction.

In exchange for the TexStar Rich Gas System (the “Contribution”), we paid $80 million in cash to TexStar, assumed $100 million of debt (which was immediately repaid by the Partnership’s new term loan facility, as described below) and issued 14,633,000 Class B Convertible Units to TexStar.

Due to the interest of Southcross Energy LLC (which, at the time of the Contribution, owned a significant stake in our outstanding units and 100% of our General Partner) in the Contribution, the conflicts committee of the board of directors of our General Partner reviewed the terms of the definitive agreement for the Contribution and approved our entry into it. The conflicts committee, composed of two of our independent directors, retained separate counsel and an independent financial advisor, which rendered a fairness opinion.

Consummation of Holdings Transaction

Contemporaneously with the consummation of the Contribution, Southcross Energy LLC, which previously owned a significant stake in our outstanding units and 100% of our General Partner, completed its combination with TexStar.

As a result of the Holdings Transaction, Holdings, through its wholly-owned subsidiary Southcross Holdings Borrower LP, acquired from (a) BBTS Borrower LP (“BBTS”) 100% of TexStar and its general partner and (b) from Southcross Energy LLC 2,116,400 of our common units and 12,213,713 of our subordinated units, collectively representing an approximate 39.8% limited partner interest in us, as well as 100% of our General Partner, which owns an approximate 2% general partner interest in us and our incentive distribution rights. In November 2014, BBTS, an entity controlled by EIG and Tailwater, distributed its interest in Holdings to EIG and Tailwater in roughly equal proportions. Southcross Energy LLC is controlled by Charlesbank. As a result of the Holdings Transaction, and the subsequent distribution by BBTS of its interests to EIG and Tailwater, each of Charlesbank, EIG and Tailwater owns approximately one-third of Holdings.

Waiver of Distribution on Subordinated Units

Beginning with the third quarter of 2014, until such time that we have a Distributable Cash Flow Ratio of at least 1.0, Holdings, the holder of all of our subordinated units, waived the right to receive distributions on any subordinated units that would cause our Distributable Cash Flow Ratio to be less than 1.0. With respect to the fourth quarter of 2014, Holdings waived the requirement that any distribution owed to it for that quarter be paid with 45 days of the end of the quarter, provided that the distribution is paid before or in conjunction with the filing of this Form 10-K.

Board of Directors

The board of directors of our General Partner is comprised of seven directors. As a result of the Holdings Transaction, each of Charlesbank, EIG and Tailwater has the right to designate two directors (one of whom must be independent). The seventh member of the board of directors of the General Partner and its chairman is selected by a majority of the other directors. David W. Biegler has been designated as the chairman of the board of directors of the General Partner until the second anniversary of the closing of the Contribution or until his earlier death or resignation.

In connection with the closing of the Holdings Transaction, in August 2014, Samuel P. Bartlett and Kim G. Davis, who were affiliated with Charlesbank, resigned as directors of our General Partner, and Wallace Henderson and Jason Downie, as designees of EIG and Tailwater, respectively, were elected as directors of our General Partner.

All of our directors are compensated equally for similar responsibilities and reimbursed for expenses incurred for their services to us. For the year ended December 31, 2014, we paid Charlesbank, EIG and Tailwater $0.4 million for director fees and related expenses. These expenses are reflected in general and administrative expenses in our consolidated statements of operations.

Series A Conversion

The Holdings Transaction constituted a change of control pursuant to our Second Amended and Restated Agreement of Limited Partnership relating to our series A preferred units, giving the holders the right to convert their series A preferred units into common units based on a 110% exchange ratio. The closing price of the common units on the date of closing of the Holdings Transaction was $22.17. All of the holders of our series A preferred units, including Southcross Energy LLC, which previously owned a significant stake in our outstanding units and 100% of our General Partner, elected to convert all of their series A preferred units into common units in connection with the closing of the Holdings Transaction.

Shared Services with Southcross Holdings LP and Other Affiliates

Certain of the employees of our General Partner perform management, administrative, operational and workforce related services to affiliated entities, including Holdings, which owns 100% of our General Partner, and an affiliate that is jointly owned by EIG and Tailwater, two of our Sponsors. The expenses associated with these services, which are shared with these entities, are recorded in general and administrative in our statement of operations and are allocated among the entities. During the year ended December 31, 2014, we allocated $1.0 million to Holdings, and $0.1 million to an affiliate of two of our Sponsors.

The Conflicts Committee of the board of directors of our General Partner has reviewed the cost allocation methodology applicable to these services and, based on representations from management, determined that the fees charged were fair.

Wells Fargo Bank, N.A.

We entered into the Credit Facility with syndicates of financial institutions and other lenders. These syndicates included affiliates of Wells Fargo Bank, N.A., an affiliate of which is a member of the investor group (See Note 13 to our consolidated financial statements). Affiliates of Wells Fargo Bank, N.A. have from time to time engaged in commercial banking and financial advisory transactions with us in the normal course of business. During the year ended December 31, 2014, 2013 and 2012, we incurred costs, excluding interest, to Wells Fargo Bank, N.A. and its affiliates of $9.5 million, $1.8 million and $5.9 million, respectively.

Other Transactions with Affiliates

Under the Distribution Agreement, we made customary representations, warranties and agreements by us, including an agreement to indemnify the Managers for certain liabilities under the Securities Act. The Managers and certain of their affiliates have engaged, and may in the future engage, in commercial and investment banking transactions with us in the ordinary course of their business for which they have received, and expect to receive, customary compensation and expense reimbursement. In particular, affiliates of each of the Managers are lenders under our Credit Facility, an affiliate of Wells Fargo Securities, LLC is a lender under our Term Loan and affiliates of the other sales agents may from time to time hold positions in the Term Loan. If we use any net proceeds of this offering to repay borrowings under our Credit Facility, such affiliates of the Managers will receive proceeds of the offering.

In conjunction with the TexStar Rich Gas System Transaction, we entered into a gas gathering and processing agreement (the “G&P Agreement”) and an NGL sales agreement (the “NGL Agreement”) with an affiliate of Holdings. Under the terms of these agreements, we transport, process and sell rich natural gas for the affiliate in return for fees that are substantially equivalent to the fees that Holdings receives from its customers for such services, and we can sell natural gas liquids that we own to Holdings at prices that are substantially equivalent to prices that Holdings receives from third parties. In the future, when Holdings’ fractionation facility is operational, the NGL Agreement will permit us to utilize Holdings’ fractionation services at market-based rates.

During the year ended December 31, 2014, the Partnership recorded revenues from affiliates of $13.3 million in accordance with the G&P Agreement and the NGL Agreement. Accounts receivable due from affiliates of $10.3 million as of December 31, 2014 is comprised of primarily (a) $4.8 million due from Holdings relating to gathering and processing services in the period and (b) $2.8 million and $2.3 million due from T2 Cogen and T2 Gas Utilities respectively (as defined in Note 16) representing reimbursements for operating costs and equipment for this investment in joint ventures. Accounts payable due to affiliates of $12.9 million as of December 31, 2014 is comprised of primarily (a) $5.4 million due to Holdings relating to reimbursements of insurance and capital costs and (b) $4.6 million due to T2 Cogen, T2 Gas Utility, and T2 La Salle Gas Utility representing operational obligations for this investment in joint venture.

In 2014, we paid approximately $2.8 million to Black Creek Well Services, LP, an entity in which two of our Sponsors (EIG and Tailwater) have an indirect controlling interest, for servicing work it performed for us.

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

We have a Code of Business Conduct and Ethics that requires the board of directors of our General Partner or its Conflicts Committee to review periodically all related-person transactions that are required to be disclosed under SEC rules and, when appropriate, to authorize or ratify all such transactions. If the board of directors of our General Partner or its Conflicts Committee considers ratification of a related-person transaction and determines not to so ratify, the Code of Business Conduct and Ethics provides that our management will make all reasonable efforts to cancel or annul the transaction.

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

See Part II, Item 10 of this report for a discussion regarding director independence.

Item 14. Principal Accountant Fees and Services

We have engaged Deloitte & Touche LLP as our independent registered public accounting firm. The following table summarizes fees we have paid Deloitte & Touche LLP for the audit of our annual financial statements and other services rendered for the years ended December 31, 2014 and 2013:

	Year ended December 31,	
	2014	2013
Audit fees[1]	$1,620,455	$944,000
Audit-related fees[2]	523,236	—
Tax fees[3]	71,494	16,894
All other fees[4]	96,422	—
	$2,311,607	$960,894

(1) The Audit fees are fees billed for professional services for the audit and quarterly reviews of the Partnership's consolidated financial statements, review of other SEC filings, including registration statements, and issuance of comfort letters and consents.

(2) Audit-related fees are fees billed for assurance and related services related to consultations and audits performed in connection with acquisitions, due diligence services related to the TexStar combination transaction and assistance with the implementation of Section 404 of the Sarbanes-Oxley Act.

(3) Tax fees are billed for sales tax planning and advisory services.

(4) All other fees are fees billed in connection with certain integration services from the TexStar combination transaction.

Audit Committee Approval of Audit and Non-Audit Services

The Audit Committee of the board of directors of our General Partner has adopted a policy with respect to services which may be performed by Deloitte & Touche LLP. This policy lists specific audit-related and tax services as well as any other services that Deloitte & Touche LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional Audit Committee authorization. The Audit Committee receives quarterly reports on the status of expenditures pursuant to that policy. The Audit Committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the Audit Committee or by its chairman, to whom such authority has been conditionally delegated, prior to engagement.

The Audit Committee has approved the appointment of Deloitte & Touche LLP as independent registered public accounting firm to conduct the audit of our financial statements for the year ended December 31, 2014.

PART IV

Item 15. Exhibits and Financial Schedules

(a) Financial Statements

(1) Included in Part II, Item 8 of this report.

(2) All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibit Index.

An "Exhibit Index" has been filed as part of this report beginning in sub-item (b) below of this item and is incorporated herein by reference.

Schedules other than those listed above are omitted because they are not required, not material, not applicable or the required information is shown in the financial statements or notes thereto.

Agreements attached or incorporated herein as exhibits to this report are included to provide investors with information regarding the terms and conditions of such agreements and are not intended to provide any other factual or disclosure information about the Partnership or the other parties to the agreements.

Such agreements may contain representations and warranties by the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (i) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate, (ii) have been qualified by disclosures that were made to the other party or parties in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement, (iii) may apply standards of materiality in a way that is different from what may be viewed as material to you or other investors and (iv) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, the representations and warranties in such agreements may not describe the actual state of affairs as of the date they were made or at any other time.

(b) Exhibits and Exhibit Index

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Southcross Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-180841)).
3.2	Third Amended and Restated Agreement of Limited Partnership of Southcross Energy Partners, L.P., dated as of August 4, 2014 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K dated August 4, 2014).
3.3	Certificate of Formation of Southcross Energy Partners GP, LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-180841)).
3.4	Second Amended and Restated Limited Liability Company Agreement of Southcross Energy Partners GP, LLC, dated as of August 4, 2014 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K dated August 4, 2014).
4.1	Registration Rights Agreement, dated as of April 12, 2013, by and between Southcross Energy Partners, L.P. and Southcross Energy LLC (incorporated by reference to Exhibit 4.1 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.1	Third Amended and Restated Revolving Credit Agreement, dated as of August 4, 2014, by and among Southcross Energy Partners, L.P., Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, JPMorgan Chase Bank, N.A., as Documentation Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated August 4, 2014).
10.2	Term Loan Credit Agreement, dated as of August 4, 2014, by and among Southcross Energy Partners, L.P., Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K dated August 4, 2014).
10.3#	Southcross Energy Partners, L.P. 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K dated November 7, 2012).
10.4#	Form of Phantom Unit Award Agreement (incorporated by reference to Exhibit 10.5 to the Registration Statement on Form S-1 (Commission File No. 333-180841)).
10.5#	Southcross Energy Partners GP, LLC and Southcross GP Management Holdings, LLC 2014 Equity Incentive Plan and Form of Unit Award Agreement (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K dated August 4, 2014).
10.6#	Severance Agreement, dated as of August 6, 2009, by and between Southcross Energy LLC and David W. Biegler (incorporated by reference to Exhibit 10.6 to the Registration Statement on Form S-1 (Commission File No. 333-180841)).
10.7#	Severance Agreement, dated as of April 2, 2012, by and between Southcross Energy Partners GP, LLC and J. Michael Anderson (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 (Commission File No. 333-180841)).
10.8#	Southcross Energy Partners GP, LLC Non-Employee Director Compensation Arrangement (incorporated by reference to Exhibit 10.12 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2012).
10.9#	Southcross Energy Partners, L.P. Non-Employee Director Deferred Compensation Plan (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2012).
10.10	Contribution Agreement, dated as of June 11, 2014, by and among TexStar Midstream Services, LP, Southcross Energy Partners, L.P. and Southcross Energy GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated June 11, 2014).
10.11#*	Employment Agreement, dated as of March 5, 2015, by and between Southcross Energy Partners GP, LLC and John E. Bonn.

Exhibit Number	Description
10.12#	Retention Agreement, dated as of November 6, 2014, by and between Southcross Energy Partners GP, LLC and J. Michael Anderson (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2014).
21.1*	List of Subsidiaries of Southcross Energy Partners, L.P.
23.1*	Consent of Deloitte & Touche LLP.
31.1*	Certification of Chief Executive Officer required by Rule 13a-14(a)/15d-14(a).
31.2*	Certification of Chief Financial Officer required by Rule 13a-14(a)/15d-14(a).
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
101.INS*†	XBRL Instance Document
101.SCH*†	XBRL Taxonomy Extension Schema
101.CAL*†	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*†	XBRL Taxonomy Extension Definition Linkbase
101.LAB*†	XBRL Taxonomy Extension Label Linkbase
101.PRE*†	XBRL Extension Presentation Linkbase

* Filed or furnished herewith.

\# As required by Item 15(a)(3) of Form 10-K, this exhibit is identified as a compensatory plan or arrangement.

† Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections. The financial information contained in the XBRL (eXtensible Business Reporting Language)-related documents is unaudited and unreviewed.

(c) Financial Statement Schedules

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Southcross Energy Partners, L.P.
By: Southcross Energy Partners GP, LLC, our General Partner

By: /s/ JOHN E. BONN
John E. Bonn
Chief Executive Officer

Dated: March 6, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the registrant and in the capacities and on the dates indicated have signed this report below.

SIGNATURE	TITLE	DATE
/s/ JOHN E. BONN John E. Bonn	Chief Executive Officer *(Principal Executive Officer)*	March 6, 2015
/s/ J. MICHAEL ANDERSON J. Michael Anderson	Senior Vice President and Chief Financial Officer *(Principal Financial Officer)*	March 6, 2015
/s/ DONNA A. HENDERSON Donna A. Henderson	Vice President and Chief Accounting Officer *(Principal Accounting Officer)*	March 6, 2015
/s/ PHILLIP M. MEZEY Phillip M. Mezey	Executive Vice President, Business Development	March 6, 2015
/s/ DAVID W. BIEGLER David W. Biegler	Chairman of the Board	March 6, 2015
/s/ JON M. BIOTTI Jon M. Biotti	Director	March 6, 2015
/s/ JASON DOWNIE Jason Downie	Director	March 6, 2015
/s/ WALLACE HENDERSON Wallace Henderson	Director	March 6, 2015
/s/ JERRY W. PINKERTON Jerry W. Pinkerton	Director	March 6, 2015
/s/ RONALD G. STEINHART Ronald G. Steinhart	Director	March 6, 2015
/s/ BRUCE A. WILLIAMSON Bruce A. Williamson	Director	March 6, 2015

SOUTHCROSS ENERGY

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