Southcross Energy Partners, L.P.
Form 10-Q
August 06, 2014
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from to

Commission File Number: 001-35719

Southcross Energy Partners, L.P.
(Exact name of registrant as specified in its charter)

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

(214) 979-3720
(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 ý No o

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

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

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

Indicate the number of units outstanding of the issuer’s classes of common units, subordinated units and Class B Convertible Units, as of the latest practicable date:

As of August 6, 2014, the registrant has 23,497,782 common units outstanding, 12,213,713 subordinated units outstanding and 14,633,000 Class B Convertible Units outstanding. Our common units trade on the NYSE under the symbol “SXE.”

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Commonly Used Terms

As generally used in the energy industry and in this Quarterly Report on Form 10-Q, 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

MMBtu: One million British thermal units

Mcf: One thousand cubic feet

Mgal: One thousand gallons

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: 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 and 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, normal butane and natural gasoline

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FORWARD-LOOKING INFORMATION

Investors are cautioned that certain statements contained in this Quarterly Report on Form 10-Q 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 a “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 and in our 2013 Annual Report on Form 10-K.

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 Quarterly Report on Form 10-Q 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;
- 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, 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 in respect of our acquisition of the TexStar Rich Gas System;
- 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;
- 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 Quarterly Report on Form 10-Q may not, in fact, occur. Accordingly, undue reliance should not be placed on these statements.

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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.

Update to Risk Factors

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 Environmental Protection Agency (the “EPA”) has adopted regulations controlling GHG emissions under its existing Clean Air Act (“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, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of 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. Our Gregory and Conroe processing facilities are currently required to report under this rule. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of GHG emissions by regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. We timely submitted the reports required under this rule and have adopted procedures for future required reporting. 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. 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 Prevention of Significant Deterioration (“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 (“BACT”) 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.

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

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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 involve 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 Southcross Holdings LP 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;
- the incurrence of significant charges, such as asset devaluation or restructuring charges; and
- environmental or regulatory compliance matters or liabilities.

If these risks or other unanticipated liabilities were to materialize, the desired benefits of the acquisition of theTexStar 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 Southcross Holdings LP, which could limit our ability to maintain or increase distributions to our unitholders.

Southcross Holdings LP 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 Southcross Holdings LP.

The consummation of any such purchases will depend upon, among other things, our ability to reach an agreement with Southcross Holdings LP regarding the terms of such purchases (which will require the approval of the conflicts committee of the board of directors of our general partner) and our ability to finance such purchases on acceptable terms. Additionally, Southcross Holdings LP 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 Southcross Holdings LP of any additional assets would be restricted or prohibited by such covenants, we or Southcross Holdings LP 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 Southcross Holdings LP's current or future assets, our ability to maintain or increase distributions to our unitholders may be limited.

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PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except for unit data)
(Unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$10,908	$3,349
Trade accounts receivable	63,925	57,669
Prepaid expenses	1,285	3,061
Other current assets	6,588	5,105
Total current assets	82,706	69,184
Property, plant and equipment, net	662,755	575,795
Intangible assets, net	1,539	1,568
Other assets	5,280	5,768
Total assets	$752,280	$652,315
LIABILITIES, PREFERRED UNITS AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$84,214	$62,451
Other current liabilities	5,984	5,344
Total current liabilities	90,198	67,795
Long-term debt	226,850	267,300
Other non-current liabilities	2,256	1,692
Total liabilities	319,304	336,787
Commitments and contingencies (Note 7)		
Series A convertible preferred units (1,832,399 and 1,769,915 units issued and outstanding as of June 30, 2014 and December 31, 2013, respectively)	46,805	40,504
Partners' capital:		
Common units (23,163,713 and 13,963,713 units authorized; 21,465,046 and 12,253,985 units outstanding as of June 30, 2014 and December 31, 2013, respectively)	289,465	169,141
Subordinated units (12,213,713 units authorized and outstanding as of June 30, 2014 and December 31, 2013)	87,887	99,726
General Partner interest	8,819	6,367
Accumulated other comprehensive loss	—	(210)
Total partners' capital	386,171	275,024
Total liabilities, preferred units and partners' capital	$752,280	$652,315

See accompanying notes.

SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except for unit and per unit data)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$195,063	$154,703	$408,654	$298,954
Expenses:				
Cost of natural gas and liquids sold	168,826	133,407	355,229	258,795
Operations and maintenance	11,745	10,284	22,606	20,173
Depreciation and amortization	8,978	8,261	17,506	15,510
General and administrative	6,693	5,582	12,796	11,623
Gain on sale of assets	(45)	—	(42)	—
Total expenses	196,197	157,534	408,095	306,101
Income (loss) from operations	(1,134)	(2,831)	559	(7,147)
Interest expense	(1,771)	(3,101)	(4,744)	(5,148)
Loss before income tax expense	(2,905)	(5,932)	(4,185)	(12,295)
Income tax expense	(56)	(260)	(64)	(279)
Net loss	(2,961)	(6,192)	(4,249)	(12,574)
Series A convertible preferred unit in-kind distribution	(738)	(560)	(1,272)	(560)
Series A preferred unit valuation adjustment to maximum redemption value	(5,062)	(4,666)	(5,029)	(4,666)
Net loss attributable to partners	(8,761)	(11,418)	(10,550)	(17,800)
General partner's interest in net loss	(59)	(124)	(84)	(252)
Limited partners' interest in net loss	$(8,702)	$(11,294)	$(10,466)	$(17,548)
Earnings per unit and distributions declared				
Net loss allocated to limited partner common units	$(7,382)	$(7,982)	$(8,398)	$(11,108)
Weighted average number of limited partner common units outstanding	21,472,420	12,222,692	19,887,523	12,218,178
Loss per common unit	$(0.34)	$(0.65)	$(0.42)	$(0.91)
Distributions declared per common unit	$0.40	$0.40	$0.80	$0.80
Net loss allocated to limited partner subordinated units	$(1,320)	$(3,312)	$(2,068)	$(6,440)
Weighted average number of limited partner subordinated units outstanding	12,213,713	12,213,713	12,213,713	12,213,713
Loss per subordinated unit	$(0.11)	$(0.27)	$(0.17)	$(0.53)

See accompanying notes.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss	$(2,961)	$(6,192)	$(4,249)	$(12,574)
Other comprehensive income (loss):				
Hedging losses reclassified to earnings and recognized in interest expense	106	100	221	194
Adjustment in fair value of derivatives	—	40	(11)	(30)
Total other comprehensive income	106	140	210	164
Comprehensive loss	$(2,855)	$(6,052)	$(4,039)	$(12,410)

See accompanying notes.

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Cash flows from operating activities:		
Net loss	$(4,249)	$(12,574)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	17,506	15,510
Unit-based compensation	1,611	1,093
Amortization of deferred financing costs	675	602
Gain on sale of assets	(42)	—
Unrealized loss on financial instruments	312	—
Other, net	54	19
Changes in operating assets and liabilities:		
Trade accounts receivable	(5,526)	2,349
Prepaid expenses and other current assets	2,128	823
Other non-current assets	(20)	(69)
Accounts payable and accrued liabilities	12,107	(7,123)
Other liabilities	(855)	(966)
Net cash provided by (used in) operating activities	23,701	(336)
Cash flows from investing activities:		
Capital expenditures	(55,891)	(69,449)
Expenditures for assets subject to property damage claims, net of insurance proceeds and deductibles	(970)	(2,622)
Proceeds from sale of assets	45	24
Business acquisition	(38,636)	—
Net cash used in investing activities	(95,452)	(72,047)
Cash flows from financing activities:		
Proceeds from issuance of common units, net	144,671	—
Borrowings under our credit agreements	134,000	85,500
Repayments under our credit agreements	(174,450)	(40,000)
Payments on capital lease obligations	(307)	(261)
Financing costs	(166)	(2,045)
Proceeds from issuance of Series A convertible preferred units, net of issuance costs	—	38,835
Contributions from general partner	3,115	800
Payments of distributions and distribution equivalent rights	(27,516)	(15,955)
LTIP tax withholdings on vested units	(37)	—
Net cash provided by financing activities	79,310	66,874
Net increase (decrease) in cash and cash equivalents	7,559	(5,509)
Cash and cash equivalents — Beginning of period	3,349	7,490
Cash and cash equivalents — End of period	$10,908	$1,981

See accompanying notes.

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SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(In thousands)
(Unaudited)

	Partners' Capital Limited Partners				
	Common	Subordinated	General Partner	Accumulated Other Comprehensive Loss	Total
BALANCE - December 31, 2013	$169,141	$99,726	$6,367	$(210)	$275,024
Net loss	(2,580)	(1,584)	(85)	—	(4,249)
Issuance of common units, net	144,671	—	—	—	144,671
Unit-based compensation on long-term incentive plan	1,513	—	—	—	1,513
Series A convertible preferred unit in-kind distribution and fair value adjustment	(5,802)	(474)	(25)	—	(6,301)
Contributions from general partner	—	—	3,115	—	3,115
Cash distributions paid	(17,166)	(9,771)	(579)	—	(27,516)
Accrued distribution equivalent rights on long-term incentive plan	(259)	—	—	—	(259)
LTIP tax withholdings on vested units	(37)	—	—	—	(37)
General partner unit in-kind distribution	(16)	(10)	26	—	—
Net effect of cash flow hedges	—	—	—	210	210
BALANCE - June 30, 2014	$289,465	$87,887	$8,819	$—	$386,171

	Partners' Capital Limited Partners				
	Common	Subordinated	General Partner	Accumulated Other Comprehensive Loss	Total
BALANCE - December 31, 2012	$194,365	$125,951	$6,628	$(477)	$326,467
Net loss	(6,168)	(6,165)	(241)	—	(12,574)
Series A preferred unit in-kind distribution	(275)	(274)	(11)	—	(560)
Series A preferred unit valuation adjustment to maximum value	(4,666)	—	—	—	(4,666)
Issuance of Series A preferred units, net	—	—	—	—	—
Issuance of general partner units	—	—	800	—	800
Unit-based compensation on long term incentive plan	800	—	—	—	800
Cash distributions paid	(7,818)	(7,818)	(319)	—	(15,955)
Net effect of cash flow hedges	—	—	—	164	164
Accrued distribution on long term incentive plan	(100)	—	—	—	(100)
BALANCE - June 30, 2013	$176,138	$111,694	$6,857	$(313)	$294,376

See accompanying notes.

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SOUTHCROSS ENERGY PARTNERS, L.P.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. ORGANIZATION, DESCRIPTION OF BUSINESS

Organization

Southcross Energy Partners, L.P. (the "Partnership," "Southcross," "we," "our" or "us") is a Delaware limited partnership formed in April 2012. Our common units are listed on the New York Stock Exchange under the symbol "SXE." Southcross Energy LLC is a Delaware limited liability company. Prior to the closing of the combination of Southcross Energy LLC and TexStar Midstream Services, LP ("TexStar") on 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 combined and created a newly formed partnership, Southcross Holdings LP ("Holdings"). Holdings owns 100% of our General Partner (and thus controls us) and certain other equity interests in us, as well as 100% of the equity of TexStar. EIG Global Energy Partners, Charlesbank Capital Partners and Tailwater Capital LLC each indirectly own approximately one-third of Holdings. Simultaneously with the closing of the combination transactions, we acquired the Rich Gas System which was under common control of TexStar (the "TexStar Rich Gas System"). For additional details regarding the transactions see Note 14.

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, as of June 30, 2014, include three gas processing plants, two fractionation plants and our pipelines. We are headquartered in Dallas, Texas and our operations are managed as and presented in one reportable segment.

Segments

Our chief operating decision-maker is our General Partner's Chief Executive Officer who reviews financial information presented on a consolidated basis in order to make decisions about resource allocations and assess our performance. 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

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the Securities and Exchange Commission and in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial statements. Accordingly, these condensed consolidated financial statements do not include all of the disclosures required by GAAP and should be read with our 2013 Annual Report on Form 10-K. The condensed consolidated financial statements as of June 30, 2014 and December 31, 2013, and for the three and six months ended June 30, 2014 and 2013, are unaudited and have been prepared on the same basis as the audited financial statements included in our 2013 Annual Report on Form 10-K. All intercompany accounts and transactions have been eliminated in the preparation of the accompanying condensed consolidated financial statements. The condensed consolidated financial statements reflect the assets acquired and liabilities assumed as of June 30, 2014 and the operating results for the period from March 6, 2014 through June 30, 2014 associated with the acquisition discussed further in Note 2. Adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the results of operations and financial position have been included herein.

The accompanying unaudited condensed consolidated financial statements were prepared in conformity with GAAP, which 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. Information for interim periods may not be indicative of our operating results for the entire year.

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The disclosures included in this Quarterly Report on Form 10-Q provide an update to our 2013 Annual Report on Form 10-K.

We evaluate events that occur after the balance sheet date, but before the financial statements are issued, for potential recognition or disclosure. Based on the evaluation, we determined that there were no material subsequent events for recognition or disclosure other than those disclosed in this Quarterly Report.

Significant Accounting Policies

During the second quarter of 2014, there were no material changes to our significant accounting policies described in Note 1 of our 2013 Annual Report on Form 10-K.

Recent Accounting Pronouncements

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

In May 2014, the Financial Accounting Standard Board and the International Accounting Standard Board jointly issued a comprehensive new revenue recognition standard that will supersede nearly all existing revenue recognition guidance under GAAP and International Financial Reporting Standards. 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. The adoption could have a significant impact on our consolidated financial statements.

2. ACQUISITIONS

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.

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 three months ended June 30, 2014 and there were no changes to the preliminary balances previously recorded.
The reconciliation of 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	

During the six months ended June 30, 2014, we expensed $0.3 million of transaction costs associated with the acquisition. These costs are reported within general and administrative expenses in our statement of operations.

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The following unaudited pro forma financial information for the three months ended June 30, 2013 and the six months ended June 30, 2014 and 2013 assumes that the pipeline acquisition 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 acquisition (in thousands, except unit information):

	Three months ended June 30,	Six months ended June 30,	
	2013	2014	2013
Total revenue	$155,754	$409,303	$301,041
Net loss	(6,740)	(4,357)	(13,984)
Net loss attributable to common unitholders	(8,275)	(8,463)	(11,863)
Net loss per common unit—(basic and diluted)	(0.56)	(0.43)	(0.81)
Net loss attributable to subordinated unitholders	(3,556)	(2,109)	(7,069)
Net loss per subordinated unit—(basic and diluted)	(0.29)	(0.17)	(0.58)

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 three months ended June 30, 2014, Onyx contributed $1.3 million in revenues and $0.4 million in net income to our statements of operations. For the six months ended June 30, 2014, Onyx contributed $1.6 million in revenues and $0.3 million in net income to our statements of operations.

As discussed in Note 14, we acquired the TexStar Rich Gas System on August 4, 2014.

3. NET LOSS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS

Net Loss Per Limited Partner Unit

The following is a reconciliation of the net loss attributable to our limited partners and our limited partner units and the basic and diluted earnings per unit calculations for the three and six months ended June 30, 2014 and 2013 (in thousands, except unit and per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss	$(2,961)	$(6,192)	$(4,249)	$(12,574)
Series A Preferred Unit in-kind distribution and fair value adjustment (1)	(5,800)	(5,226)	(6,301)	(5,226)
Net loss attributable to partners	$(8,761)	$(11,418)	$(10,550)	$(17,800)
General partner's interest (2)	$(59)	$(124)	$(84)	$(252)
Limited partners' interest (2)				
Common	$(7,382)	$(7,982)	$(8,398)	$(11,108)
Subordinated	$(1,320)	$(3,312)	$(2,068)	$(6,440)

(1) The Series A Preferred Unit in-kind distribution increased the net loss attributable to partners as of June 30, 2014 in the calculation of earnings per unit (See Note 9) for the three months ended June 30, 2014. The valuation adjustment to maximum redemption value of the Series A Preferred Units as of June 30, 2014 increased the net loss available to common units in the calculation of earnings per unit (See Note 9) for the three months ended June 30, 2014 and 2013 and the six months ended June 30, 2014 and 2013.

(2) General Partner's and Limited Partners' interest 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.

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	Three Months Ended June 30,		Six Months Ended June 30,	
Common Units	2014	2013	2014	2013
Interest in net loss	$(7,382)	$(7,982)	$(8,398)	$(11,108)
Effect of dilutive units - numerator (1)	—	—	—	—
Dilutive interest in net loss	$(7,382)	$(7,982)	$(8,398)	$(11,108)
Weighted-average units - basic	21,472,420	12,222,692	19,887,523	12,218,178
Effect of dilutive units - denominator (1)	—	—	—	—
Weighted-average units - dilutive	21,472,420	12,222,692	19,887,523	12,218,178
Basic and diluted net loss per common unit	$(0.34)	$(0.65)	$(0.42)	$(0.91)

	Three Months Ended June 30,		Six Months Ended June 30,	
Subordinated Units	2014	2013	2014	2013
Interest in net loss	$(1,320)	$(3,312)	$(2,068)	$(6,440)
Effect of dilutive units - numerator (1)	—	—	—	—
Dilutive interest in net loss	$(1,320)	$(3,312)	$(2,068)	$(6,440)
Weighted-average units - basic	12,213,713	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	12,213,713
Basic and diluted net loss per subordinated unit	$(0.11)	$(0.27)	$(0.17)	$(0.53)

(1) Because we had a net loss for the three and six months ended June 30, 2014 and 2013, 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. The weighted average units that would be included in the computation of diluted per unit amounts in accordance with the treasury stock method were 51,334 and 21,287 unvested awards granted under our long-term incentive plan (See Note 11) and 1,832,399 and 1,816,556 Series A Preferred Units (See Note 9) for the three and six months ended June 30, 2014, respectively. The amount of unvested common units that were not included in the computation of diluted per unit amounts were 161,400 and 148,506 unvested awards granted under our long-term incentive plan and 1,398,667 and 703,197 Series A Preferred Units for the three and six months ended June 30, 2013. Diluted net income per limited partner unit reflects the potential dilution that could occur if securities or agreements to issue common units, such as awards under the long-term incentive plan, were exercised, settled or converted into common units. When it is determined that potential common units resulting from an award should be included in the diluted net income per limited partner unit calculation, the impact is reflected by applying the treasury stock method.

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

The Series A Preferred Units are considered participating securities for purposes of the basic earnings per unit calculation during periods in which they receive cash distributions. We are required to pay in-kind distributions to the Series A Preferred Units for the first four full quarters beginning the quarter ended June 30, 2013, and continuing until the Series A Preferred Units have been converted into common units (See Note 9). Because the Series A Preferred Units have received in-kind distributions, they have been excluded from the basic earnings per unit calculation for the three and six months ended June 30, 2014. In connection with the combination of Southcross Energy LLC and TexStar on August 4, 2014 (see Note 14 for details), all holders of the Series A Preferred Units elected to convert their

Series A Preferred Units into common units.

Distributions

Our current partnership agreement (“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 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 we have a distributable cash flow divided by cash distributions ("Distributable Cash Flow Ratio") of at least 1.0, 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.

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 the second amendment to our $350.0 million Second Amended and Restated Credit Agreement with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders (as amended, our "Credit Facility") (See Note 6 and Note 9). 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) or, beginning after four full quarters, such higher per unit rate as is paid in respect to our common units. Cash distributions will 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.

The following table represents the paid in-kind ("PIK") distribution earned for the period ended June 30, 2014 and the PIK distribution for the previous periods (in thousands, except per unit and in-kind distribution units):

Payment Date	Attributable to the Quarter Ended	Per Unit Distribution		In-Kind Series A Preferred Unit Distributions to Series A Preferred Holders	In-Kind Series A Preferred Distributions Value(3)	In-Kind Unit Distribution to General Partner	In-Kind General Partner Distribution Value(3)
2014							
August 14, 2014	June 30, 2014	$0.40		32,066	$738	654	$ 15
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	(1)	22,276	512	454	10
August 14, 2013	June 30, 2013	0.20	(2)	2,199	51	45	1

(1) 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.
(2) 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.
(3) 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.

The Series A Preferred Units were convertible into common units based on an exchange ratio of 110.0% of the Series A Preferred Units if a third party acquires majority ownership control of our General Partner or we sell substantially all of our assets. In connection with the combination of Southcross Energy LLC and TexStar (see Note 14 for details), 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 110.0% exchange ratio. 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 quarter ended June 30, 2014, but will receive a cash distribution on the converted units.

Cash Distributions

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The following table represents our distribution declared for the period ended June 30, 2014 and distributions paid for the prior periods (in thousands, except per unit data):

				Distributions			
	Attributable to the	Per Unit		Limited Partners			
Payment Date	Quarter Ended	Distribution		Common	Subordinated	General Partner	Total
2014							
August 14, 2014	June 30, 2014	$0.40	(1)	$8,593	$4,885	$290	$13,768
May 15, 2014	March 31, 2014	0.40		8,586	4,885	290	13,761
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 does not include the distribution payment to the Series A Unit holders that converted Series A Units into common units or units that vested as part of the LTIP as a result of the combination of Southcross Energy LLC and TexStar (see Note 11 and Note 14 for details).
(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 initial public offering on November 7, 2012.

Also, in accordance with our long-term incentive plan, we pay distribution equivalent rights to holders of units granted under that plan that vest during the year (See Note 11).

4. 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 swaps.
- 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.

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Derivative Financial Instruments

Interest Rate Swaps

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. to reduce the risk associated with the variability of interest rates for our term loan borrowings. 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 three and six months ended June 30, 2014 and 2013.

In February 2014, we discontinued cash flow hedge accounting on a prospective basis, as a result of the $148.5 million temporary repayment of borrowings under our Credit Facility (See Note 10). The fair value 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.

In June 2014, we entered into new interest rate swap contracts, which became effective in July 2014, with an aggregate notional value of $140.0 million and a maturity date of June 30, 2015. We receive a floating rate based upon one-month LIBOR and pay a fixed rate of 0.327%. 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 immediately in interest expense.

The fair value of our interest rate swaps is determined based on a discounted cash flow method using the contractual terms of the swaps. The floating coupon rate is based on observable rates consistent with the frequency of the interest cash flows. As of June 30, 2014 and December 31, 2013, the current portion of the interest rate swap liability of $0.2 million and $0.3 million, respectively, was included within other current liabilities. As of June 30, 2014 and December 31, 2013, there was no non-current portion of the interest rate swaps liability.

The fair values of our interest rate swap liabilities were as follows (in thousands):

	Significant Other Observable Inputs (Level 2)	
	Fair value measurement as of	
	June 30, 2014	December 31, 2013
Interest rate swap liabilities	$ 180	$ 263

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Change in value recognized in other comprehensive loss - effective portion	$—	$40	$(11)	$(30)
Loss reclassified from accumulated other comprehensive loss to interest expense	106	100	221	194

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

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Realized loss on interest rate derivatives	$27	$27	$53	$54
Unrealized loss on interest rate swap derivatives	168	—	180	—

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 for the outstanding month-ahead swap contracts as of June 30, 2014 and December 31, 2013 was 37,320 MMBtu per day and 33,722 MMBtu per day, respectively. 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. As of December 31, 2013, the fair value of $0.1 million was included within other current assets. As of June 30, 2014, there was no value for commodity swaps included within other current liabilities.

We have elected to present our commodity swaps net in the balance sheet. We did not have any cash collateral received or paid on our commodity swaps as of June 30, 2014. The effect of offsetting in our balance sheet was as follows (in thousands):

	June 30, 2014		December 31, 2013	
	Other Current Assets	Other Current Liabilities	Other Current Assets	Other Current Liabilities
Gross Amounts of Recognized Assets / (Liabilities)	$—	$(12)	$140	$(20)
Gross Amounts Offset in the Balance Sheet	—	—	(20)	20
Net Amount	$—	$(12)	$120	$—

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Realized gain (loss) on derivatives	$81	$(10)	$(1,088)	$(57)
Unrealized loss on derivatives	(175)	—	(131)	—

5. LONG-LIVED ASSETS

Property, Plant and Equipment

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

	Estimated Useful Life (yrs)	June 30, 2014	December 31, 2013
Pipelines	30	$383,041	$344,721
Gas processing, treating and other plants	15	260,289	254,133
Compressors	7	20,459	20,030
Rights of way and easements	15	24,998	20,729
Furniture, fixtures and equipment	5	3,576	3,347
Capital lease vehicles	3-5	1,834	1,396
Total property, plant and equipment		694,197	644,356
Accumulated depreciation and amortization		(97,323)	(79,908)
Total		596,874	564,448
Construction in progress		43,314	6,039
Land and other		22,567	5,308

Property, plant and equipment, net	$662,755	$575,795

Depreciation is provided using the straight-line method based on the estimated useful life of each asset.

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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 in January 2013, we experienced a fire at this facility. In connection with the fire, as of June 30, 2014, we have spent approximately $6.1 million to return the facility to service and filed an insurance claim related to these costs. We have recovered $1.0 million in 2013 and $0.6 million in 2014 from insurance proceeds for this loss and believe it is probable that we will recover the remaining costs, less a $0.3 million deductible, under our insurance policies.

Intangible Assets

Intangible assets of $1.5 million and $1.6 million as of June 30, 2014 and 2013, respectively, represent the unamortized value assigned to the 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. Amortization expense in the consolidated financial statements presented and over the next five years related to intangible assets for the periods presented is not material.

6. LONG-TERM DEBT

Credit Facility

In November 2012, we entered into the Credit Facility, which had a five-year maturity. We could utilize the Credit Facility for working capital requirements and capital expenditures, the purchase of assets, the payment of distributions and other general purposes. In connection with the closing of the purchase of the TexStar Rich Gas System, we re-financed our existing Credit Facility and entered into a new Term Loan Facility (See Note 14 and Note 8). Our outstanding debt and information related to our Credit Facility at June 30, 2014 and December 31, 2013 is as follows (in thousands):

	June 30, 2014	December 31, 2013
Credit Facility, due November 2017	$226,850	$267,300
Outstanding letters of credit	$25,930	$31,260
Remaining unused borrowings	$97,220	$69
Applicable margin under LIBOR borrowings	2.7 %	4.5 %

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Weighted average interest rate	2.7 %	4.6 %	3.6 %	4.1 %
Average outstanding borrowings	$189,993	$235,191	$191,567	$231,184
Maximum borrowings	$226,850	$257,000	$267,300	$257,000

Under our Credit Facility, we had the ability to borrow up to $350.0 million less any letters of credit outstanding. Borrowings under our Credit Facility bear interest at LIBOR plus an applicable margin or a base rate as defined in the respective credit agreements. The fair value of the debt funded through our Credit Facility approximates its carrying amount as of June 30, 2014 and December 31, 2013 due primarily to the variable nature of the interest rate of the instrument.

Our Credit Facility contained various covenants and restrictive provisions and required maintenance of certain financial and operational compliance covenants. As of June 30, 2014 and December 31, 2013, we were in compliance with all of our loan covenants. All of our assets were pledged as collateral under our Credit Facility. The terms of our Credit Facility contained customary covenants, including those that restrict our ability to make or limit certain payments, distributions, acquisitions, loans, or investments, incur certain indebtedness or create certain liens on our assets, consolidate or enter into mergers, dispose of certain of our assets, engage in certain types of transactions with our affiliates, enter into certain sale/leaseback transactions and modify certain material agreements.

Amendments to Credit Facility

During the fourth quarter of 2012 and into the first quarter of 2013, we encountered operational challenges including the January 2013 fire at our Gregory facility and contractual disputes with a former third party processor. These items impacted our operating results adversely and resulted in the need to amend our Credit Facility with the First Amendment and the Second Amendment (each as described below). Due to the benefits from an equity raise during the first quarter of 2014 and improved financial performance, we entered into the Third Amendment and the Fourth Amendment (each as described below), respectively, which reverted certain terms of the Credit Facility back to the original terms.

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First Amendment to Credit Facility

On March 27, 2013, we entered into the first amendment (the "First Amendment") to the Credit Facility. As a result of the First Amendment, our available credit 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 (the "Collateral Account") and letters of credit outstanding. Amounts on deposit in the Collateral Account were pledged as collateral to the Credit Facility. Pursuant to the First Amendment, we were permitted to pay our quarterly cash distribution of available cash for the first quarter of 2013 regardless of whether we met certain financial covenants for the period ending March 31, 2013. Because the First Amendment did not modify our requirement to meet the financial covenants under the Credit Facility beginning March 31, 2013, and because we believed it was unlikely that we would be in compliance with our financial covenants for the quarter ending March 31, 2013, we further amended our Credit Facility as discussed below. In connection with the First Amendment, we incurred \$0.6 million in fees, which were deferred and are being amortized over the remaining life of the Credit Facility.

Second Amendment to Credit Facility

On April 12, 2013, we entered into the limited waiver and second amendment (the "Second Amendment") to the Credit Facility, which waived our defaults relating to financial covenants in the Credit Facility for the period ended March 31, 2013 and provided more favorable financial covenants until we provided notice under the Credit Facility that we have achieved a consolidated total leverage ratio (the "Target Leverage Ratio") of 4.25 to 1.00 for one quarter or 4.50 to 1.00 for two consecutive quarters, calculated excluding the benefit of cash on deposit in the Collateral Account and any equity cure amounts (the "Target Leverage Test"). See the Fourth Amendment discussion below regarding the Target Leverage Test. Our available credit, excluding our letters of credit, continued to be subject to the availability limits described in the First Amendment. In connection with the Second Amendment, we incurred \$1.5 million in fees, which were deferred and are being amortized over the remaining life of the Credit Facility.

The Second Amendment provided for, among other things, the following:

- established our letters of credit sublimit at \$50.0 million;
- until we achieved the Target Leverage Ratio:
    - an increase in our interest rate to LIBOR plus 4.50%;
- a limit to our growth capital expenditures of \$25.0 million for the last three quarters of 2013 and an additional \$25.0 million for the subsequent 18-months ending June 30, 2015 (provided that if additional cash, as required under the Second Amendment, is placed in the Collateral Account, such expenditures could have been increased to \$28.0 million for the remaining three quarters of 2013 and the subsequent 18-months ending June 30, 2015);
- distributions to our unitholders were effectively limited to our established minimum quarterly distribution of \$0.40 per unit; and
- our ability to make acquisitions was limited; and
- once we achieved the Target Leverage Ratio, we had the option to revert certain provisions of the Credit Facility back to the terms of our original Credit Facility (See Fourth Amendment to Credit Facility below).

Third Amendment to Credit Facility

On January 29, 2014, we entered into the Third Amendment (the "Third Amendment") to our Credit Facility. Pursuant to the Third Amendment, we were able to (a) acquire a specified target entity or its assets, provided that, among other things, the aggregate consideration paid by us in connection with such acquisition did not exceed \$40.0 million and (b) make certain capital expenditures with respect to the addition to our pipeline systems into Webb County, Texas (the "Webb Pipeline").

In addition, the Third Amendment decreased our Maximum Adjusted Consolidated Total Leverage Ratio (as defined in our Credit Facility) to 5.75 to 1.00 for the March 31, 2014 calculation period when we (a) received net cash proceeds in a specified amount pursuant to permitted equity offerings and (b) initiated construction of the Webb Pipeline in accordance with the terms of our Credit Facility. In connection with the Third Amendment, we incurred $0.1 million in fees, which were deferred and are being amortized over the remaining life of the Credit Facility.

Fourth Amendment to Credit Facility

On March 13, 2014, we entered into the Fourth Amendment (the “Fourth Amendment”) to the Credit Facility. Concurrently with the Fourth Amendment becoming effective, we exercised the Target Leverage Option established pursuant to the Second

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Amendment and satisfied a leverage ratio of less than 4.25 to 1.00 calculated on a pro forma basis for the debt outstanding, after the net proceeds from the equity issuance were used to pay off debt, and utilizing the Adjusted EBITDA, as provided in the Fourth Amendment, for the period ended December 31, 2013. An effect of us exercising the Target Leverage Option was the removal of the $250.0 million availability limit as provided for in the First Amendment and returning the availability under the Credit Facility to its original $350.0 million, less any letters of credit outstanding.
Pursuant to the Fourth Amendment, all funds previously deposited in the Collateral Account were released from the liens and security interests and are no longer pledged as collateral securing our obligations under the Credit Facility. As a result of the Fourth Amendment and our exercise of the Target Leverage Option, certain other provisions of the Credit Facility reverted to the requirements and terms in effect before the Second Amendment. The effects of such reversion are that, among other things, (a) the Applicable Margin has been reset to the current applicable level in the pricing grid based on our pro forma Consolidated Total Leverage (as defined in our Credit Facility) immediately upon closing of the Fourth Amendment, (b) the $25.0 million limit on growth capital expenditures for the 18-month period ending June 30, 2015 is no longer effective and (c) certain limitations on unit distributions imposed by the Second Amendment are no longer effective. In connection with the Fourth Amendment, we incurred $0.1 million in fees, which were deferred and are being amortized over the remaining life of the Credit Facility.

Concurrently with the Fourth Amendment and as a result of our acquisition in March 2014, our maximum consolidated total leverage ratio was increased to 5.00 to 1.00 through September 30, 2014.

The Credit Facility contained various covenants and restrictive provisions and also required maintenance of certain financial and operational covenants including but not limited to the following:

- beginning October 1, 2014 and prior to exercising a one-time covenant election in connection with the issuance of certain unsecured notes, a consolidated total leverage ratio (generally defined as debt to EBITDA, as adjusted) of not more than 4.50 to 1.00, and a consolidated interest coverage ratio of not less than 2.50 to 1.00. The requirement to maintain a certain consolidated total leverage ratio was subject to a provision for increases to 5.00 to 1.00 in connection with certain acquisitions; and

- upon exercising a one-time covenant election in connection with the issuance of certain unsecured notes, a consolidated total leverage ratio of not more than 5.25 to 1.00, a consolidated senior secured leverage ratio of not more than 3.50 to 1.00 and a consolidated interest coverage ratio of not less than 2.50 to 1.00.

As a result of the combination of Southcross Energy LLC and TexStar, on August 4, 2014 we entered into new debt arrangements. See Note 14 for additional details.

7. COMMITMENTS AND CONTINGENCIES

Legal Matters

On March 5, 2013, one of our subsidiaries filed suit against Formosa Hydrocarbons Company, Inc. (“Formosa”). The lawsuit seeks recoveries of losses that we believe our subsidiary experienced as a result of the failure of Formosa to perform certain of its obligations under the gas processing and sales contract between the parties. Formosa filed a response generally denying our claims and filed counterclaims against our subsidiary claiming our affiliate breached the gas processing and sales contract, defrauded Formosa in connection with the alleged breach and breached a related agreement between the parties for the supply by Formosa of residue gas to a third party on behalf of our subsidiary. We believe the counterclaims are without merit and our subsidiary will defend itself vigorously against the counterclaims while continuing to pursue its own claims. We cannot predict the outcome of such litigation or the timing of any related recoveries or payments.

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. There currently are no such pending proceedings to which we are a party that our management believes 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

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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 that are recorded in other current liabilities and other non-current liabilities in our consolidated balance sheet as of June 30, 2014. The lease termination dates of the agreements vary from 2014 until 2018. We recorded amortization expense related to the capital leases of $0.1 million and $0.3 million for the three and six months ended June 30, 2014, respectively. We recorded amortization expense related to the capital lease of $0.1 million and $0.2 million for the three and six months ended June 30, 2013, respectively.

Capital leases entered into during the three and six months ended June 30, 2014 were $0.1 million and $0.5 million, respectively. Capital leases entered into during the three and six months ended June 30, 2013 were $0.1 million and $1.2 million, respectively.

Operating Leases

We maintain operating leases in the ordinary course of business. These leases include those for office and other operating facilities and equipment. The lease termination dates of the agreements vary from 2014 to 2025. Expenses associated with operating leases were $0.4 million and $0.7 million for the three and six months ended June 30, 2014, respectively. Expenses associated with operating leases were $0.3 million and $0.8 million for the three and six months ended June 30, 2013, respectively.

Purchase Commitments

On June 30, 2014, we had commitments of approximately $19.4 million for purchases of material and equipment related to our capital projects, primarily our Webb Pipeline project. We have other planned capital projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures.

8. TRANSACTIONS WITH RELATED PARTIES

Charlesbank

As of June 30, 2014, the board of directors of our General Partner includes three persons affiliated with Charlesbank and three outside directors. All of these directors are compensated equally for similar responsibilities and reimbursed for expenses incurred for their services to us. For the three and six months ended June 30, 2014, we paid fees related to the Charlesbank director services of $0.1 million and $0.2 million, respectively, which are reflected in general and administrative expenses in our consolidated statements of operations. For the three and six months ended June 30, 2013, we paid fees related to the Charlesbank director services of $0.1 million and $0.3 million, respectively, which are reflected in general and administrative expenses in our consolidated statements of operations. As a result of the combination of Southcross Energy LLC and TexStar on August 4, 2014, there have been changes to the board of directors of our General Partner. See Note 14 for additional details.

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 three and six months ended June 30, 2014, we incurred expenses of $7.7 million and $15.1 million, respectively, related to these reimbursements, which are reflected in operating and general and administrative expenses in our consolidated statements of operations. During the three and six months ended June 30, 2013, we incurred expenses of $6.2 million and $12.1 million, respectively, related to these reimbursements, which are reflected in operating and general and administrative expenses in our consolidated statements of operations.

The reimbursement of our compensation expenses to our General Partner is in accordance with our Partnership Agreement. Compensation expense for services incurred by us as of June 30, 2014 on behalf of Southcross Energy LLC were billed to

Southcross Energy LLC. For the three and six months ended June 30, 2014, compensation expense of $0.3 million was billed to Southcross Energy LLC, which was not incurred on our behalf.

During the second quarter of 2013, we entered into a Purchase Agreement (as defined below) with Southcross Energy LLC, pursuant to which 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 9). 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. See Note 14.

Wells Fargo Bank, N.A.

During the first quarter of 2014, we entered into amendments to our 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 6). 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. Total fees paid, excluding interest, to Wells Fargo Bank, N.A. and its affiliates were $0.2 million during the first quarter of 2014 relating to the Third Amendment and Fourth Amendment of the Credit Facility. During the three and six months ended June 30, 2013, we incurred costs of $1.4 million and $2.0 million, respectively, to Wells Fargo Bank, N.A. and its affiliates. In connection with the closing we refinanced our Credit Facility and entered into a new Term Loan Facility. See Note 14.

9. SERIES A 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.

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 (See Note 6). The Private Placement 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.

Applicable accounting guidance related to the Series A Preferred Units requires that equity instruments with redemption features that are redeemable at the option of the holder be classified outside of permanent equity. The change of control rights associated with the Series A Preferred Units requires the units to be classified outside of permanent equity. The Series A Preferred Units were adjusted to maximum redemption value as of June 30, 2014 because the maximum redemption value is currently different than the fair value of the units at issuance. The adjustment in the valuation adjustment to issuance value and the distributions associated with the Series A Preferred Units of $5.8 million have been included in the calculation of partners’ capital and earnings per unit for the three months ended June 30, 2014. The adjustment in the valuation adjustment to issuance value and the distributions associated with the Series A Preferred Units of $6.3 million have been included in the calculation of partners’ capital and earnings per unit for the six months ended June 30, 2014. Additionally, none of the identified embedded derivatives relating to the terms of the Series A Preferred Units require bifurcation, as each embedded derivative was determined to be clearly and closely related to the host contract. All of the Series A Preferred Units, including the units held by Southcross Energy LLC, were converted into common units on August 4, 2014. See Note 14.

Voting Rights: The Series A Preferred Units were a class of voting equity security that ranks 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 vote 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) is entitled to one vote for each common unit into which such Series A Preferred Unit is convertible on each matter with respect to which each common unit is 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 determines to begin paying quarterly distributions in cash, and thereafter in cash. In-kind distributions will be 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) or, beginning after four full quarters, such higher per unit rate as is paid in respect of our common units. Cash distributions will equal the greater of $0.40 per unit per quarter or the quarterly distribution paid with respect to each common unit.

Conversion Rights: The Series A Preferred Units are convertible into common units based on an exchange ratio of 110.0% of the Series A Preferred Units if a third party acquires majority ownership control of our General Partner or we sell substantially all of our assets, in either case before January 1, 2015. In connection with the combination of Southcross Energy LLC and TexStar (see Note 14 for details), 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 110.0% 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 Series A Preferred Units will rank equally with the rest of our common units with respect to rights on dissolution and liquidation.

10. PARTNERS' CAPITAL

Common Units

In February 2014, we completed a public equity offering of 9,200,000 additional common units for $144.7 million, net of expenses, and received a capital contribution from our General Partner to maintain its 2.0% interest in us. The net proceeds from the offering are being used to fund the construction of our Webb Pipeline, were used for our acquisition in March 2014 and are being used for general partnership purposes. We temporarily repaid borrowings under our Credit Facility during the first quarter of 2014, which we are redrawing to fund the construction of the new pipeline and for other general purposes.

Our common units represent limited partner interests in us. The holders of our common units are entitled to participate in partnership distributions and are entitled to exercise the rights and privileges available to limited partners under our Partnership Agreement. We had 21,465,046 and 12,253,985 common units issued and outstanding as of June 30, 2014 and December 31, 2013, respectively. In connection with the acquisition of the TexStar Rich Gas System and the combination of Southcross Energy LLC and TexStar on August 4, 2014, we issued Class B Convertible units, accelerated the vesting of the LTIP units (See Note 11), and all of the holders of the Series A Preferred Units elected to convert their Series A Preferred Units into common units based on an exchange ratio of 110.0%. See Note 14 for additional details.

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. We had 12,213,713 subordinated units issued and outstanding as of June 30, 2014 and December 31, 2013. Beginning with the third quarter of 2014, until such time we have a Distributable Cash Flow Ratio of at least 1.0, 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.

General Partner Interests

Our general partner interest consisted of 724,495 general partner units as of June 30, 2014 and 534,638 general partner units as of December 31, 2013. In connection with other equity issuances including issuances related to the acquisition of the TexStar Rich Gas System and the combination of Southcross Energy LLC and TexStar, 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 3).

11. INCENTIVE COMPENSATION
Unit Based Compensation
Long-Term Incentive Plan
On November 7, 2012, and in connection with our initial public offering, we established our 2012 Long-Term Incentive Plan ("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 in either a common unit or an

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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.

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

	Units	Weighted-average fair value at grant date
Unvested - December 31, 2013	182,673	$ 22.55
Granted units	315,721	17.10
Forfeited units	(200)	23.01
Units recaptured for tax withholdings	(2,108)	19.97
Vested units	(5,292)	19.95
Unvested - June 30, 2014	490,794	$ 19.43

For the six months ended June 30, 2014 and 2013, we granted awards under the LTIP with a grant date fair value of $5.4 million and $0.7 million, respectively, which we have classified as equity awards. As of June 30, 2014 and June 30, 2013, we had total unamortized compensation expense of $7.5 million and $3.0 million, respectively, related to these awards. The awards were expected to be amortized over a three-year vesting period from each equity awards' grant date. The combination of Southcross Energy LLC and TexStar on August 4, 2014 resulted in a change of control of our General Partner and accelerated the vesting of all the LTIP awards outstanding on that date. As of June 30, 2014 and June 30, 2013, we had 1,213,642 and 1,579,621 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 expense on our consolidated statements of operations (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Unit-based compensation	$1,082	$685	$1,611	$1,093

Employee Savings Plan

We have employee savings plans under Sections 401(a) and 401(k) of the Internal Revenue Code ("IRC") whereby employees of our General Partner may contribute a portion of their base compensation to the employee savings plan, subject to limits under the IRC. 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 pay 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 consolidated statements of operations (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Matching contributions expensed for employee savings plan	$234	$161	$590	$310

12. REVENUES

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Sales of natural gas	$123,401	$106,552	$268,759	$204,861
Sales of NGLs and condensate	54,282	33,792	106,155	66,212
Transportation, gathering and processing fees	17,279	14,175	33,394	27,520
Other	101	184	346	361
Total revenues	$195,063	$154,703	$408,654	$298,954

13. CONCENTRATION OF CREDIT RISK AND TRADE ACCOUNTS RECEIVABLE

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 three and six months ended June 30, 2014 and 2013 represent the following percentages of consolidated revenue:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Top ten customers	73.0 %	57.7 %	68.6 %	59.6 %

The percentage of total consolidated revenue for each customer that exceeded 10% of total revenues for the three and six months ended June 30, 2014 and 2013 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Trafigura AG	13.0 %	(a)	12.6 %	(a)
Sherwin Alumina Company	12.2 %	12.9 %	11.0 %	12.5 %
Dow Hydrocarbons & Resources LLC	(a)	10.9 %	(a)	(a)
Formosa Hydrocarbons Co., Inc.	(a),(b)	(a),(b)	(a),(b)	12.3 %

(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.

For the six months ended June 30, 2014 and 2013, we did not experience significant non-payment for services. At June 30, 2014, we did not record an allowance for uncollectible accounts receivable.

14. SUBSEQUENT EVENTS

Partnership Distribution

On July 25, 2014, the Board of Directors of our General Partner (the "Board") declared a cash distribution of $0.40 per common unit, subordinated unit and General Partner unit, which will be paid on August 14, 2014 to unitholders of record on August 8, 2014.

Acquisition of the TexStar Rich Gas System

On August 4, 2014, we acquired 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 new term loan agreement) and issued 14,633,000 of our newly-established 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 rich natural gas gathering and residue pipelines across the core producing areas extending from Dimmit to Karnes Counties in the liquids-rich window of the Eagle Ford shale. These pipelines are operated under a split-capacity joint venture with Atlas Pipeline Partners LP.

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Class B Convertible Units Payment-in-kind

To establish the Class B Convertible Units, on August 4, 2014 we amended and restated our agreement of limited partnership and entered into a Third Amended and Restated Agreement of Limited Partnership (as amended and restated, the “Third A&R Partnership Agreement”). 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 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.

The Third A&R Partnership Agreement does not allow additional Class B Convertible Units (other than Class B PIK Units and the 14,633,000 Class B Convertible Units issued in connection with the Contribution) to be issued without the prior approval of our General Partner and the holders of a majority of the outstanding Class B Convertible Units.

The Third A&R 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.

Distributions

Commencing with the quarter ending 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.

Conversion

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 Distributable Cash Flow (as defined in the Third A&R Partnership Agreement) in an amount sufficient to pay, and actually 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

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

Consummation of Combination Transactions

Contemporaneously with the consummation of the Contribution, Southcross Energy LLC (“Southcross Energy”), which previously owned a significant stake in our outstanding units and 100% of our General Partner, completed its previously disclosed combination with TexStar (the “Combination Transactions”).

As a result of the Combination Transactions, Southcross Holdings LP ("Southcross Holdings"), through Southcross Holdings Borrower LP, a wholly owned subsidiary of Southcross Holdings ("Southcross Borrower"), 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 2.0% interest in us and our incentive distribution rights. BBTS was controlled by EIG Global Energy Partners and Tailwater Capital, and Southcross Energy LLC was controlled by Charlesbank Partners. The Contribution Transactions resulted in Charlesbank Capital Partners, EIG Global Energy Partners and Tailwater Capital (collectively, the "Sponsors") each indirectly owning approximately one-third of Southcross Holdings.

Board of Directors

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The Board will continue to be comprised of seven directors. As a result of the Contribution Transactions, BBTS will have the right to designate four directors (two of whom must be independent) and Southcross Energy LLC will have the right to designate two directors (one of whom must be independent). The seventh member of the Board and its chairman will be selected by a majority of the other directors. David W. Biegler has been designated as the chairman of the Board for two years or until his earlier death or resignation.

In connection with the closing of the Contribution Transactions, on August 4, 2014, Samuel P. Bartlett and Kim G. Davis resigned as directors of our General Partner, and Wallace Henderson and Jason Downie, as designees of BBTS, were elected as directors of our General Partner. Messrs. Bartlett and Davis did not resign as the result of any disagreement with us or our General Partner.

Conversion of Series A Preferred Units into common units

Pursuant to the change in control provision in our Second Amended and Restated Agreement of Limited Partnership applicable to our Series A Preferred Units, all of the holders of the Series A Preferred Units elected to convert their Series A Preferred Units into common units based on an exchange ratio of 110.0%.

New Debt Arrangements

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 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 Credit Agreement, the “Senior Credit Facilities”).

The initial borrowings and extensions of credit under the Term Loan Agreement were used to finance the acquisition of the TexStar Rich Gas System (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 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.

Third A&R Credit Agreement

The Third A&R Credit Agreement is a five-year $200 million revolving credit facility. Pursuant to the Third A&R Credit Agreement, among other things:

(a) the letters of credit sublimit is increased to $75 million;

(b) we are given 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” is 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 each of September 30, 2014 and 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;

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(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 12-month period or more than four times during the term of the facility) to cure such Financial Covenant Default by having the Sponsors purchase equity interests in or make capital contributions to us resulting in, among other things, proceeds that, if added to the minimum financial requirements, 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.

Term Loan Agreement

The Term Loan Agreement is a seven-year $450 million senior secured term loan facility. On August 4, 2014, the lenders funded the full amount of the facility. 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 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 Credit Agreement;

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

(e) the facility will amortize in equal quarterly installments in an aggregate annual mount 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 Credit Agreement).

2014 Equity Incentive Plan

On August 4, 2014, our General Partner and Southcross GP Management Holdings, LLC, a newly formed entity of which Southross 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 (and, as applicable, the board of directors of the general partner of Southcross 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 (as amended and restated, the "A&R LLC Agreement"). The A&R LLC Agreement establishes a new class of non-voting units for issuance pursuant to the 2014 Incentive Plan and designates Southcross Holdings as our General Partner's managing member.

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15. SUPPLEMENTAL INFORMATION

Supplemental Cash Flow Information (in thousands)

	Six Months Ended June 30,	
	2014	2013
Supplemental Disclosures:		
Cash paid for interest, net of amounts capitalized	$4,200	$5,703
Cash received for tax refunds	185	87
Supplemental schedule of non-cash investing and financing activities:		
Accounts payable related to capital expenditures	9,656	29,288
Change in value recognized in other comprehensive income	11	30
Capital lease obligation	466	(1,240)
Accrued distribution equivalent rights (DERs) on the LTIP units	259	100
Series A convertible preferred unit in-kind distribution and fair value adjustment	6,301	5,226
Other	1,688	—

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):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Total interest costs	$2,225	$3,501	$5,297	$6,148
Capitalized interest included in property, plant and equipment, net	(454)	(400)	(553)	(1,000)
Interest expense	$1,771	$3,101	$4,744	$5,148

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):

	2014
Deferred financing costs, January 1	$5,237
Capitalization of deferred financing costs (1)	166
Less:	
Amortization of deferred financing costs	(675)
Deferred financing costs, June 30	$4,728

(1) See Note 6.

Southcross Assets Considered Leases to Third Parties

On March 6, 2014, we acquired natural gas pipelines and contracts related to these pipelines (See Note 2). The pipelines transport natural gas to two power plants in Nueces County, Texas under fixed-fee contracts. The contracts have a primary term through 2029 and an option to extend the agreements by an additional term of up to ten years. These contracts are considered operating leases under the applicable accounting guidance.

Future minimum annual demand payment receipts under these agreements as of June 30, 2014, respectively, were as follows: $2.2 million in 2014 of which a portion was paid prior to our acquisition, $5.6 million in 2015, $5.6 million in 2016, $5.6 million in 2017, $2.2 million in 2018, $2.2 million in 2019 and $15.3 million thereafter. The revenue recognized for the

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demand payments is recognized on a straight-line basis over the term of the contract. The demand fee revenues under the contracts were $0.7 million and $0.9 million for the three and six months ended June 30, 2014 and have been included within transportation, gathering and processing fees within Note 12. The amounts do not include contingent fees based on the actual gas volumes delivered under the contracts. Contingent fees were $0.3 million and 0.4 million for the three and six months ended June 30, 2014.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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. Our common units are listed on the New York Stock Exchange under the symbol "SXE." Southcross Energy LLC is a Delaware limited liability company. Prior to the closing of the combination of Southcross Energy LLC and TexStar Midstream Services, LP ("TexStar") on 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 combined and created a newly formed partnership, Southcross Holdings LP ("Holdings"). Holdings owns 100% of our General Partner (and thus controls us) and certain other equity interests in us, as well as 100% of the equity of TexStar. EIG Global Energy Partners, Charlesbank Capital Partners and Tailwater Capital LLC each indirectly own approximately one-third of Holdings. Simultaneously with the closing of the combination transactions, we acquired the Rich Gas System which was under common control of TexStar (the "TexStar Rich Gas System"). For additional details regarding the transactions see Part I, Item I, Note 14, "Subsequent Events" of this Quarterly Report on Form 10-Q.

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, as of June 30, 2014, include three gas processing plants, two fractionation plants and our pipelines. Our South Texas assets are located in or near the Eagle Ford shale region. We are headquartered in Dallas, Texas.
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 the resulting NGLs into the various components and selling or delivering pipeline quality natural gas 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

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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.

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 margins from these arrangements (in thousands):

	Three Months Ended June 30,						Six Months Ended June 30,					
	2014			2013			2014			2013		
	Gross margin	%		Gross margin	%		Gross margin	%		Gross margin	%	
Fixed-fee	$17,290	65.9	%	$14,247	66.9	%	$33,543	62.8	%	$27,645	68.8	%
Fixed-spread	2,471	9.4	%	3,145	14.8	%	6,357	11.9	%	9,912	24.7	%
Sub-total	19,761	75.3	%	17,392	81.7	%	39,900	74.7	%	37,557	93.5	%
Commodity-sensitive	6,476	24.7	%	3,904	18.3	%	13,525	25.3	%	2,602	6.5	%
Total gross operating margin	$26,237	100.0	%	$21,296	100.0	%	$53,425	100.0	%	$40,159	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 (i) volume, (ii) gross operating margin, (iii) operations and maintenance expenses, (iv) Adjusted EBITDA and (v) 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 contract 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.

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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, plus interest expense, income tax expense, depreciation and amortization expense, certain non-cash charges such as non-cash equity compensation and unrealized gains/losses on derivative contracts, major litigation net of recoveries, transaction expense, revenue deferral adjustment and selected charges that are unusual or non-recurring; less interest income, income tax benefit, unrealized gains on commodity derivative contracts 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, less cash paid for interest (net of capitalized costs and fair value changes associated with interest rate swap contracts), income tax expense and maintenance capital expenditures. We use distributable cash flow to analyze our performance. 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):

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Reconciliation of gross operating margin to net loss				
Gross operating margin	$26,237	$21,296	$53,425	$40,159
(Deduct):				
Income tax expense	(56)	(260)	(64)	(279)
Interest expense	(1,771)	(3,101)	(4,744)	(5,148)
Gain on sale of assets	45	—	42	—
General and administrative expense	(6,693)	(5,582)	(12,796)	(11,623)
Depreciation and amortization expense	(8,978)	(8,261)	(17,506)	(15,510)
Operations and maintenance expense	(11,745)	(10,284)	(22,606)	(20,173)
Net loss	$(2,961)	$(6,192)	$(4,249)	$(12,574)

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

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	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Reconciliation of Net Cash Flows Provided by Operating Activities to Net Loss and Adjusted EBITDA				
Net cash provided by (used in) operating activities	$9,525	$1,375	$23,701	$(336)
Add (deduct):				
Depreciation and amortization expense	(8,978)	(8,261)	(17,506)	(15,510)
Unit-based compensation	(1,082)	(685)	(1,611)	(1,093)
Deferred financing costs amortization	(338)	(335)	(675)	(602)
Gain on sale of assets	45	—	42	—
Unrealized loss	(343)	—	(312)	—
Other, net	(40)	(19)	(54)	(19)
Changes in operating assets and liabilities:				
Trade accounts receivable	(1,952)	6,298	5,526	(2,349)
Prepaid expenses and other	(1,315)	377	(2,128)	(823)
Other non-current assets	(5)	57	20	69
Accounts payable and accrued expenses	1,587	(4,602)	(12,107)	7,123
Other liabilities	(65)	(397)	855	966
Net loss	$(2,961)	$(6,192)	$(4,249)	$(12,574)
Add (deduct):				
Depreciation and amortization expense	$8,978	$8,261	$17,506	$15,510
Interest expense	1,771	3,101	4,744	5,148
Income tax expense	56	260	64	279
Unrealized loss	175	—	131	—
Revenue deferral adjustment	444	—	1,626	—
Unit-based compensation	1,082	685	1,611	1,093
Gain on sale of assets	(45)	—	(42)	—
Major litigation costs, net of recoveries	630	—	903	—
Transaction expenses for acquisition	4	—	307	—
Other, net	44	19	62	19
Expenses associated with significant items	—	113	—	1,314
Adjusted EBITDA	$10,178	$6,247	$22,663	$10,789
(Deduct):				
Cash interest, net of capitalized costs	$(1,256)	$(2,745)	$(3,871)	$(4,524)
Income tax expense	(56)	(260)	(64)	(279)
Maintenance capital expenditures	(1,375)	(635)	(2,739)	(1,345)
Distributable cash flow	$7,491	$2,607	$15,989	$4,641

Current Year Highlights

The following events took place during the six months ended June 30, 2014 and have impacted, or are likely to impact, our financial condition and results of operations.

Public Equity 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 of common units were $144.7 million. The net proceeds from the offering are being used to fund the construction of our new pipeline extending into Webb County, Texas, were used to fund our acquisition in March 2014 and are being used for general partnership purposes. Pending use of the funds, we temporarily repaid borrowings under our Credit Facility (as defined below in "Credit Facility"), which we are redrawing to fund the construction of the new Webb County, Texas pipeline and for other general purposes.

Credit Facility

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On March 13, 2014, we entered into the Fourth Amendment (the “Fourth Amendment”) to the Second Amended and Restated Credit Agreement, dated as of November 7, 2012, by and among us, as borrower, Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders party thereto (as amended, the “Credit Facility”). Concurrently with the Fourth Amendment becoming effective, we exercised the Target Leverage Option established pursuant to the Second Amendment (the “Second Amendment”) to the Credit Facility and satisfied a leverage ratio of less than 4.25 to 1.00 calculated on a pro forma basis for the debt outstanding and utilizing the EBITDA, adjusted as provided in the Fourth Amendment, for the period ended December 31, 2013. As a result of the Fourth Amendment and our exercise of the Target Leverage Option, certain provisions of the Credit Facility reverted to the requirements and terms in effect before the First Amendment to the Credit Facility (the “First Amendment”) and the Second Amendment, including, but not limited to, the removal of the $250.0 million availability limit as provided for in the First Amendment and returning the availability under the Credit Facility to its original $350.0 million. See further discussion included in Part I, Item 1, Note 6, of this Quarterly Report on Form 10-Q.

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. During the six months ended June 30, 2014, we expensed $0.3 million of transaction costs associated with the acquisition.

Webb Pipeline Construction

During the first quarter of 2014, we began construction of an addition to our pipeline systems by approximately 90 miles into Webb County, Texas (the “Webb Pipeline”). During the six months ended June 30, 2014, we incurred $33.8 million in capitalized costs related to the Webb Pipeline.

TexStar Rich Gas System Acquisition

On August 4, 2014, we acquired the TexStar Rich Gas System for approximately $450 million, consisting of $80 million in cash, the assumption of $100 million of debt (which was immediately repaid through our new term loan agreement) and our issuance of 14,633,000 of our newly established Class B Convertible Units. The TexStar Rich Gas System consists of a 300 MMcf/d cryogenic processing plant, located in Bee County, Texas, and over 230 miles of rich natural gas gathering and residue pipelines across the core producing areas extending from Dimmit to Karnes Counties in the liquids-rich window of the Eagle Ford shale. These pipelines are operated under a split-capacity joint ventures with Atlas Pipeline Partners.

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Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$195,063	$154,703	$408,654	$298,954
Expenses:				
Cost of natural gas and liquids sold	168,826	133,407	355,229	258,795
Operations and maintenance	11,745	10,284	22,606	20,173
Depreciation and amortization	8,978	8,261	17,506	15,510
General and administrative	6,693	5,582	12,796	11,623
Gain on sale of assets	(45)	—	(42)	—
Total expenses	196,197	157,534	408,095	306,101
Income (loss) from operations	(1,134)	(2,831)	559	(7,147)
Interest expense	(1,771)	(3,101)	(4,744)	(5,148)
Loss before income tax expense	(2,905)	(5,932)	(4,185)	(12,295)
Income tax expense	(56)	(260)	(64)	(279)
Net loss	$(2,961)	$(6,192)	$(4,249)	$(12,574)
Other financial data:				
Adjusted EBITDA	$10,178	$6,247	$22,663	$10,789
Gross operating margin	26,237	21,296	53,425	40,159
Maintenance capital expenditures	1,375	635	2,739	1,345
Growth capital expenditures	$43,429	$19,604	$53,152	$68,104
Operating data:				
Average throughput volumes of natural gas (MMBtu/d) (1)				
South Texas	498,464	393,717	474,977	412,635
Mississippi/Alabama	186,487	190,796	204,293	197,041
Total average throughput volumes of natural gas	684,951	584,513	679,270	609,676
Average volume of processed gas (MMBtu/d)	268,297	217,315	257,420	228,474
Average volume of NGLs sold (Bbls/d)	16,386	10,740	15,363	10,448
Realized prices on natural gas volumes ($/MMBtu)	$4.67	$4.19	$4.88	$3.80
Realized prices on NGL volumes ($/gal)	0.87	0.82	0.91	0.83

(1) Current and historical average throughput volumes of natural gas per day include sales, transportation, fuel and shrink volumes. Historical average throughput volumes of natural gas per day presented previously was based on sales and transportation volume only.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Volume and overview. Our average throughput volume of natural gas per day increased 100,437 MMBtu/d, or 17%, to 684,951 MMBtu/d during the three months ended June 30, 2014, compared to 584,513 MMBtu/d during the three months ended June 30, 2013, due primarily to increased gas volumes in South Texas as a result of the pipelines acquired from Onyx as well as new customers contracts added and increases in volume from existing customers in the Eagle Ford area during 2014. Processed gas volumes increased 50,982 MMBtu/d or 23%, to 268,297 MMBtu/d during the three months ended June 30, 2014, compared to 217,315 MMBtu/d during the three months ended June 30, 2013. This increase is due primarily to expanded volumes from the Eagle Ford shale producing area during the three months ended June 30, 2014.

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The average volume of NGLs produced for the three months ended June 30, 2014 was 16,386 Bbls/d, an increase of 5,646 Bbls/d, or 53%, compared to 10,740 Bbls/d for the three months ended June 30, 2013. This increase was due primarily to the impact of additional volumes of rich gas processed and enhanced operational efficiency at our facilities during the three months ended June 30, 2014 compared to the three months ended June 30, 2013.

Gross operating margin for the three months ended June 30, 2014 was $26.2 million, compared to $21.3 million for the three months ended June 30, 2013. This increase of $4.9 million, or 23%, was due primarily to increased processed gas volumes and increased transportation, gathering and processing fees, as well as the results of the pipelines acquired from Onyx.

Adjusted EBITDA increased by $3.9 million, or 63%, to $10.2 million for the three months ended June 30, 2014, compared to $6.2 million for the three months ended June 30, 2013, due to higher volumes and margins from processing and fractionation activities partially offset by higher operating and general and administrative expenses. We had a net loss of $3.0 million for the three months ended June 30, 2014 compared to net loss of $6.2 million for the three months ended June 30, 2013. Net loss decreased due to higher Adjusted EBITDA, offset by higher depreciation expense.

Revenues. Our total revenues for the three months ended June 30, 2014 were $195.1 million, compared to $154.7 million for the three months ended June 30, 2013. This increase of $40.4 million, or 26%, was due primarily to revenue from sales of natural gas increasing by $16.8 million from an increase in realized prices in natural gas as well as additional sales volumes. Additionally, revenue increased from sales of NGLs and condensate by $20.5 million for the three months ended June 30, 2014. The increase was due to higher NGL volumes produced in our facilities and higher realized NGL prices.

Cost of natural gas and NGLs sold. Our cost of natural gas and NGLs sold for the three months ended June 30, 2014 was $168.8 million, compared to $133.4 million for the three months ended June 30, 2013. This increase of $35.4 million, or 27%, was due primarily to higher realized natural gas prices and increased natural gas volumes purchased, as well as increased NGL volumes purchased and higher realized NGL prices compared to the same period in 2013.

Operations and maintenance expense. Operations and maintenance expense for the three months ended June 30, 2014 was $11.7 million, compared to $10.3 million for the three months ended June 30, 2013. This increase of $1.5 million, or 14%, was due primarily to increased labor and benefits costs of $0.7 million from additional headcount and higher utilities costs of $0.3 million from an increase in gas processed during the three months ended June 30, 2014 compared to the three months ended June 30, 2013 and costs associated with the pipeline acquisition from Onyx.

General and administrative (“G&A”) expenses. G&A expenses for the three months ended June 30, 2014 were $6.7 million, compared to $5.6 million for the three months ended June 30, 2013. This increase of $1.1 million, or 20%, was due primarily to increased expenses related to labor and benefits costs of $0.6 million from additional headcount, higher legal costs of $0.2 million from ongoing litigation and higher insurance costs of $0.2 million for the three months ended June 30, 2014 compared to the three months ended June 30, 2013.

Depreciation and amortization expense. Depreciation and amortization expense for the three months ended June 30, 2014 was $9.0 million, compared to $8.3 million for the three months ended June 30, 2013. The increase of $0.7 million, or 9%, was due primarily to depreciation of capital projects placed in service during and after the three months ended June 30, 2013.

Interest expense. For the three months ended June 30, 2014, interest expense was $1.8 million, compared to $3.1 million for the three months ended June 30, 2013. This decrease of $1.3 million, or 43%, was due to lower average borrowings and a decrease in our weighted average borrowing rate of 2.7% for the three months ended June 30, 2014 compared to 4.6% for the three months ended June 30, 2013. The borrowing rate increased in April 2013 as a result of the Second Amendment and subsequently decreased during March 2014 due to the Fourth Amendment and the exercise of the Target Leverage Option.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Volume and overview. Our average throughput volume of natural gas per day increased 69,594 MMBtu/d, or 11%, to 679,270 MMBtu/d during the six months ended June 30, 2014, compared to 609,676 MMBtu/d during the six months ended June 30, 2013, due primarily to increased gas volumes in South Texas as a result of the pipelines acquired from Onyx as well as new customer contracts added in the Eagle Ford area during the six months ended June 30, 2014. Processed gas volumes increased 28,946 MMBtu/d to 257,420 MMBtu/d during the six months ended June 30, 2014, compared to 228,474 MMBtu/d during the six months ended June 30, 2013. This increase is due primarily to expanded volumes from the Eagle Ford shale producing area during the six months ended June 30, 2014.

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The average volume of NGLs produced for the six months ended June 30, 2014 was 15,363 Bbls/d, an increase of 4,915 Bbls/d, or 47%, compared to 10,448 Bbls/d for the six months ended June 30, 2013. This increase was due primarily to the impact of additional volumes of rich gas processed and enhanced operational efficiency at our facilities during the six months ended June 30, 2014 compared to the six months ended June 30, 2013 during which we relied partially on third parties for NGL production.

Gross operating margin for the six months ended June 30, 2014 was $53.4 million, compared to $40.2 million for the six months ended June 30, 2013. This increase of $13.3 million, or 33%, was due primarily to increased processed gas volumes and increased transportation, gathering and processing fees, as well as the results of the pipelines acquired from Onyx.

Adjusted EBITDA increased by $11.9 million, or 110%, to $22.7 million for the six months ended June 30, 2014, compared to $10.8 million for the six months ended June 30, 2013, due to higher volumes and margins from processing and fractionation activities partially offset by higher operating and general and administrative expenses. We had a net loss of $4.2 million for the six months ended June 30, 2014 compared to net loss of $12.6 million for the six months ended June 30, 2013. Net loss decreased due to higher Adjusted EBITDA, offset by increased depreciation expense.

Revenues. Our total revenues for the six months ended June 30, 2014 were $408.7 million, compared to $299.0 million for the six months ended June 30, 2013. This increase of $109.7 million, or 37%, was due primarily to revenue from sales of natural gas increasing by $63.9 million from an increase in realized prices in natural gas as well as additional sales volumes. Additionally, revenue increased from sales of NGLs and condensate by $39.9 million for the six months ended June 30, 2014. The increase was due to higher NGL volumes produced in our facilities and higher realized NGL prices.

Cost of natural gas and NGLs sold. Our cost of natural gas and NGLs sold for the six months ended June 30, 2014 was $355.2 million, compared to $258.8 million for the six months ended June 30, 2013. This increase of $96.4 million, or 37%, was due primarily to higher realized natural gas prices and increased natural gas volumes purchased, as well as increased NGL volumes purchased and higher realized NGL prices compared to the same period in 2013.

Operations and maintenance expense. Operations and maintenance expense for the six months ended June 30, 2014 was $22.6 million, compared to $20.2 million for the six months ended June 30, 2013. This increase of $2.4 million, or 12%, was due primarily to increased labor and benefits costs of $1.2 million from additional headcount and higher utilities costs of $0.8 million from an increase in gas processed during the six months ended June 30, 2014 compared to the six months ended June 30, 2013 and costs associated with the pipeline acquisition from Onyx.

General and administrative ("G&A") expenses. G&A expenses for the six months ended June 30, 2014 were $12.8 million, compared to $11.6 million for the six months ended June 30, 2013. This increase of $1.2 million, or 10%, was due primarily to increased expenses related to labor and benefits costs of $1.2 million from additional headcount, higher legal costs of $0.7 million from ongoing litigation, offset by a reduction in professional service costs of $1.1 million for the six months ended June 30, 2014 compared to the six months ended June 30, 2013.

Depreciation and amortization expense. Depreciation and amortization expense for the six months ended June 30, 2014 was $17.5 million, compared to $15.5 million for the six months ended June 30, 2013. The increase of $2.0 million, or 13%, was due primarily to depreciation of capital projects placed in service during and after the six months ended June 30, 2013.

Interest expense. For the six months ended June 30, 2014, interest expense was $4.7 million, compared to $5.1 million for the six months ended June 30, 2013. This decrease of $0.4 million, or 8%, was due to lower average borrowings and a decrease in our weighted average borrowing rate of 3.6% for the six months ended June 30, 2014 compared to 4.1% for the six months ended June 30, 2013. The borrowing rate increased in April 2013 as a result of the Second Amendment and subsequently decreased during March 2014 due to the Fourth Amendment and the exercise of the Target Leverage Option.

Liquidity and Capital Resources

Sources of Liquidity

Our primary sources of liquidity have been cash generated from operations, investments by Southcross Energy LLC and other investors, equity raised through issuances of common and Series A Preferred Units and borrowings under our Credit Facility. Our primary cash requirements consist of operating and G&A 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.

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We expect to fund short term cash requirements, such as operating and G&A 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 Credit Facility and issuances of additional equity and debt securities, as appropriate and subject to market conditions. See further discussion included in Part I, Item 1, Note 6, "Long-Term Debt" of this Quarterly Report on Form 10-Q. As of June 30, 2014, we had $226.9 million in outstanding borrowings under our Credit Facility. Under our Credit Facility, we have the ability to borrow up to $350.0 million less any letter of credit amounts outstanding. 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 of common units were $144.7 million. We temporarily repaid borrowings under our Credit Facility, which we have begun to redraw to fund the construction of the Webb Pipeline, the acquisition in March 2014 and other general purposes. The acquisition of the pipeline included in the TexStar Rich Gas System will enable us to shorten the Webb Pipeline and reduce its capital costs by an estimated $50.0 million, compared to the originally disclosed estimated project cost of $125.0 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, whether through construction or acquisition; and
- maintenance capital expenditures, which are capital expenditures that are not considered growth capital expenditures.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Maintenance capital	$1,375	$635	$2,739	$1,345
Growth capital	43,429	19,604	53,152	68,104
Capital expenditures	$44,804	$20,239	$55,891	$69,449

Our growth capital expenditures during the six months ended June 30, 2014 related primarily to our new pipeline extending into Webb County, Texas. The growth capital expenditures during the six months ended June 30, 2013 primarily related to (i) our Bonnie View NGL fractionation facility completed in February 2013, and (ii) our Bee Line pipeline completed in February 2013.

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 strong 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 and our unused borrowings under our Credit Facility will provide liquidity to meet future short term capital requirements and to fund committed capital expenditures for the remainder of 2014. 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 Credit Facility. In March 2014, we exercised the Target Leverage Option and entered into the Fourth Amendment to the Credit Facility which removed the limitations on our ability to fund expansion projects. We believe we have and will continue to have sufficient liquidity to operate our business. Please see Part I, Item 1, Note 6, “Long-Term Debt” of this Quarterly Report on Form 10-Q for a description of our Credit Facility and Part I, Item I, Note 14, “Subsequent Events” of this Quarterly Report on Form 10-Q for a description of our new debt arrangement.

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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. Our previously announced acquisition of the TexStar Rich Gas System was closed on August 4, 2014 for approximately $450 million, consisting of $80 million in cash, the assumption of $100 million of debt (which was immediately repaid through our new term loan agreement) and 14,633,000 of our newly-issued Class B Convertible Units. For more information about the acquisition and the impact to us from the combination of TexStar Midstream Services, LP and Southcross Energy LLC. See Part I, Item I, Note 14, "Subsequent Events" of this Quarterly Report on Form 10-Q for a description of our new debt arrangement.
Cash Flows

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

	Six Months Ended June 30,	
	2014	2013
Net cash provided by (used in) operating activities	$23,701	$(336)
Net cash used in investing activities	(95,452)	(72,047)
Net cash provided by financing activities	79,310	66,874

Operating cash flows — Net cash provided by operating activities was $23.7 million for the six months ended June 30, 2014, compared to $0.3 million net cash used in operating activities for the six months ended June 30, 2013. The increase in cash from operating activities was the result of lower net loss during the six months ended June 30, 2014 compared to six months ended June 30, 2013. Also, the timing of payments for accounts receivable and accounts payable resulted in a $11.4 million increase in net cash provided by operating activities for the six months ended June 30, 2014 compared to six months ended June 30, 2013.

Investing cash flows — Net cash used in investing activities for the six months ended June 30, 2014 was $95.5 million, compared to $72.0 million for the six months ended June 30, 2013. The increase of $23.4 million primarily relates to the significant capital expenditures during 2014, including the Webb Pipeline construction costs and costs related acquisition of Onyx. During the six months ended June 30, 2014, we spent $53.2 million in growth capital and $2.7 million in maintenance capital.

Financing cash flows — Net cash provided by financing activities for the six months ended June 30, 2014 was $79.3 million, compared to $66.9 million for the six months ended June 30, 2013. The increase was due to proceeds received from our $144.7 million equity offering, net of expenses, in the first quarter of 2014. The funding raised from the equity offering was used to repay the borrowings under the Credit Facility. Also, the increase in cash provided by financing activities was offset by increased distributions paid of $11.6 million. The increased distributions was a result of the distribution paid during the six months ended June 30, 2013 being pro-rated for the initial public offering timing and the number of units outstanding increased during the six months ended June 30, 2014 due to the equity offering in the first quarter of 2014 resulting in additional distributions.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Recent Accounting Pronouncements

For information on new accounting pronouncements, see Part I, Item 1, Note 1 of this Quarterly Report on Form 10-Q.

Critical Accounting Policies and Estimates

Our critical accounting policies are described in our 2013 Annual Report on Form 10-K. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities,

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revenues and expenses. There have been no significant changes to our critical accounting policies since our 2013 Annual Report on Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

There have been no material changes to our quantitative and qualitative disclosures about market risk described in Item 7A to our 2013 Annual Report on Form 10-K.

Item 4. Controls and Procedures.

Disclosure controls and procedures. The Chief Executive Officer and Chief Financial Officer of our General Partner, who have responsibility for our management, have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)), as of the end of the period covered by this report (the “Evaluation Date”). Based on such evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective.

Internal control over financial reporting. There have been no changes in internal controls over financial reporting (as defined in Rule 13a—15(f) or Rule 15d—15(f) of the Exchange Act) during the second fiscal quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

A description of our material legal proceedings is included in Part I, Item 1, Note 7, “Commitments and Contingencies – Legal Matters” of this Quarterly Report on Form 10-Q, and is incorporated herein by reference.

Item 1A. Risk Factors.

The risk factors contained in our 2013 Annual Report on Form 10-K under Part 1A “Risk Factors” are incorporated herein by reference. The changes in our risk factors disclosed in the “Forward-Looking Information” section of this Quarterly Report on Form 10-Q are incorporated into this Item IA. by reference.

These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, results of operations, and financial condition and ability to make distributions.

Item 6. Exhibits.

The information set forth in the Index to Exhibits accompanying this report is incorporated into this Item 6 by reference.

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SIGNATURES

Pursuant to the requirements 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, its general partner
Date:	August 6, 2014	By:	/s/ J. Michael Anderson J. Michael Anderson Senior Vice President and Chief Financial Officer Principal Financial Officer
Date:	August 6, 2014	By:	/s/ Donna A. Henderson Donna A. Henderson Vice President and Chief Accounting Officer Principal Accounting Officer

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INDEX TO EXHIBITS

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 3.3 to our Current Report on Form 8-K dated August 4, 2014).
3.4	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)).
3.5	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 our 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 our Annual Report on Form 10-K dated April 15, 2013).
10.1	Contribution Agreement, dated as of June 11, 2014, among TexStar Midstream Services, L.P., Southcross Energy Partners, L.P. and Southcross Energy GP LLC (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated June 11, 2014).
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.
† 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.