Regency Energy Partners LP
Form 10-K
March 01, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2012

OR

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

For the transition period from to

Commission file number: 001-35262

REGENCY ENERGY PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	16-1731691 (I.R.S. Employer Identification No.)
2001 Bryan Street Suite 3700, Dallas, Texas (Address of principal executive offices)	75201 (Zip Code)

(214) 750-1771
(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report): None

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units of Limited Partner Interests	New York Stock Exchange

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

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

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

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 ¨

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

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

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 small reporting company" in Rule 12b-2 of the Exchange Act. ý Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer (Do not check if a smaller reporting company) ¨ Smaller reporting company

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

As of June 29, 2012, the aggregate market value of the registrant's common units held by non-affiliates of the registrant was $3,419,237,842 based on the closing sale price on such date as reported on the New York Stock Exchange.

There were 170,951,735 common units outstanding as of February 22, 2013.

DOCUMENTS INCORPORATED BY REFERENCE

None

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Introductory Statement

References in this report to the “Partnership,” “we,” “our,” “us” and similar terms refer to Regency Energy Partners LP and its subsidiaries. We use the following definitions in this annual report on Form 10-K:

Name	Definition or Description
/d	Per day
AOCI	Accumulated Other Comprehensive Income
APM	Anadarko Pecos Midstream LLC
Bbls	Barrels
Bcf	One billion cubic feet
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
Citi	Citigroup Global Markets Inc.
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFTC	Commodity Futures Trading Commission
CM	Chesapeake West Texas Processing, L.L.C.
DHS	U.S. Department of Homeland Security
DOT	U.S. Department of Transportation
EFS Haynesville	EFS Haynesville, LLC, a wholly-owned subsidiary of GECC
EIA	Energy Information Administration
ELG	Edwards Lime Gathering LLC and its wholly-owned subsidiaries, ELG Oil LLC and ELG Utility LLC
EPA	Environmental Protection Agency
EPD	Enterprise Products Partners L.P.
ERISA	Employee Retirement Income Security Act of 1974
ETC	Energy Transfer Company, the name assumed by La Grange Acquisition, L.P. for conducting business and shared services, a wholly-owned subsidiary of ETP
ETE	Energy Transfer Equity, L.P.
ETE GP	ETE GP Acquirer LLC
ETP	Energy Transfer Partners, L.P.
FASB	Financial Accounting Standards Board
FASB ASC	FASB Accounting Standards Codification
FERC	Federal Energy Regulatory Commission
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
GAAP	Accounting principles generally accepted in the United States of America
GE	General Electric Company
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer, L.P. and Regency LP Acquirer, L.P.
GECC	General Electric Capital Corporation, an indirect wholly-owned subsidiary of GE
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership through Regency Employees Management LLC
GPM	Gallons per minute
GP Seller	Regency GP Acquirer, L.P.
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of the Partnership
HLPSA	Hazardous Liquid Pipeline Safety Act
Holdco	ETP Holdco Corporation
HPC	RIGS Haynesville Partnership Co., a general partnership, and its wholly-owned subsidiary, Regency Intrastate Gas LP
ICA	Interstate Commerce Act

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Name	Definition or Description
IDRs	Incentive Distribution Rights
IPO	Initial Public Offering of Securities
IRC	Internal Revenue Code
IRS	Internal Revenue Service
KMP	Kinder Morgan Energy Partners, L.P.
LDH	LDH Energy Asset Holdings LLC
LIBOR	London Interbank Offered Rate
Lone Star	Lone Star NGL LLC
LTIP	Long-Term Incentive Plan
MBbls	One thousand barrels
MEP	Midcontinent Express Pipeline LLC
MLP	Master Limited Partnership
MMBtu	One million BTUs
MMcf	One million cubic feet
MQD	Minimum Quarterly Distribution ($0.35 per common unit)
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids, including ethane, propane, normal butane, iso butane and natural gasoline
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968, as amended
NPDES	National Pollutant Discharge Elimination System
NYMEX	New York Mercantile Exchange
NASDAQ	NASDAQ Global Select Market
NYSE	New York Stock Exchange
OSHA	Occupational Safety and Health Act
Partnership	Regency Energy Partners LP
Ranch JV	Ranch Westex JV LLC
Regency Western	Regency Western G&P LLC, an indirectly wholly owned subsidiary of the Partnership
RCRA	Resource Conservation and Recovery Act
RGS	Regency Gas Services LP, a wholly-owned subsidiary of the Partnership
RIGS	Regency Intrastate Gas System
SEC	Securities and Exchange Commission
Series A Preferred Units	Series A convertible redeemable preferred units
Services Co.	ETE Services Company, LLC
Southern Union	Southern Union Company
SUGC	Southern Union Gathering Company LLC
SXL	Sunoco Logistics Partners L.P.
TCEQ	Texas Commission on Environmental Quality
TRRC	Texas Railroad Commission
WTI	West Texas Intermediate Crude
Zephyr	Zephyr Gas Services LLC, a wholly-owned subsidiary of the Partnership

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Cautionary Statement about Forward-Looking Statements

Certain matters discussed in this report include "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "expect," "continue," "estimate," "goal," "forecast," "may" or similar expressions help identify forward-looking statements. Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we cannot give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions, including without limitation the following:

- volatility in the price of oil, natural gas and NGLs;
- declines in the credit markets and the availability of credit for us as well as for producers connected to our pipelines and our gathering and processing facilities, and for customers of our contract services business;
- the level of creditworthiness of, and performance by, our counterparties and customers;
- our access to capital to fund organic growth projects and acquisitions, and our ability to obtain debt or equity financing on satisfactory terms;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the amount of collateral required to be posted from time-to-time in our transactions;
- changes in commodity prices, interest rates and demand for our services;
- changes in laws and regulations impacting the midstream sector of the natural gas industry, including those that relate to climate change and environmental protection and safety;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- regulation of transportation rates on our natural gas and NGL pipelines;
- our ability to obtain indemnification related to cleanup liabilities and to clean up any hazardous materials release on satisfactory terms;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of production from such facilities; and
- the effect of accounting pronouncements issued periodically by accounting standard setting boards.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may differ materially from those anticipated, estimated, projected or expected.

Other factors that could cause our actual results to differ from our projected results are discussed in Item 1A of this annual report.

Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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Part I

Item 1. Business

OVERVIEW

We are a growth-oriented publicly-traded Delaware limited partnership formed in 2005 engaged in the gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring, Avalon and Granite Wash shales. Our assets are primarily located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, New Mexico and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma.

We divide our operations into five business segments:

- Gathering and Processing. We provide “wellhead-to-market” services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes our 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.
- Natural Gas Transportation. We own a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets, and a 50% membership interest in MEP, which owns an interstate natural gas pipeline with approximately 500 miles stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.
- NGL Services. We own a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in the states of Texas, Mississippi and Louisiana.
- Contract Services. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.
- Corporate. The Corporate segment comprises our corporate offices.

See Note 16 in the Notes to our Consolidated Financial Statements for additional financial information about our segments.

In February 2013, we and Regency Western entered into a contribution agreement with Southern Union, a wholly owned subsidiary of Holdco, to acquire SUGC for $1.5 billion, subject to customary post-closing adjustments. We will finance the acquisition by issuing $900 million of common units to Holdco, comprised of $750 million of our common units and $150 million of recently created Class F common units. The Class F common units are entitled to participate in our distributions for twenty-four months post-transaction closing. The remaining $600 million will be paid in cash. In addition, in conjunction with the acquisition, ETE has agreed to forgo IDR payments on the common units issued with this transaction for the twenty-four months post-transaction closing and to eliminate the $10 million annual management fee paid by us for two years post-transaction close. The transaction is expected to close in the second quarter of 2013.

Upon closing, the acquisition of SUGC will expand our presence is the Permian Basin in west Texas, one of the most prolific, high growth, oil and liquids-rich basins in North America.

Because the SUGC acquisition is a transaction between commonly controlled entities (i.e., the buyer and the sellers are each affiliates of ETE), we will be required to account for the acquisition in a manner similar to the pooling of interest method of accounting. Under this method of accounting, the SUGC acquisition will reflect historical balance sheet data for both SUGC and us instead of reflecting the fair market value of SUCG assets and liabilities. We will recast our financial statements to include the operations of SUGC from March 26, 2012 (the date upon which common control began).

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The following map depicts the geographic areas of our operations:

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ORGANIZATIONAL STRUCTURE

The chart below depicts our organizational and ownership structure as of December 31, 2012:

INDUSTRY OVERVIEW

General. The midstream natural gas industry is the link between exploration and production of raw natural gas and the delivery of its components to end-user markets. It consists of natural gas gathering, compression, dehydration, processing, amine treating, fractionation and transportation. Raw natural gas produced from the wellhead is gathered and often delivered to a plant located near the production, where it is treated, dehydrated and/or processed. Natural gas processing involves the separation of raw natural gas into pipeline quality natural gas, principally methane and mixed NGLs. Natural gas treating entails the removal of impurities, such as water, sulfur compounds, carbon dioxide and nitrogen. Pipeline-quality natural gas is delivered by interstate and intrastate pipelines to markets. Mixed NGLs are typically transported via NGL pipelines or by truck to fractionators, which separate the NGLs into their components, such as ethane, propane, normal butane, isobutane and natural gasoline. The NGL components are then sold to end users.

Natural Gas Gathering. A gathering system typically consists of a network of low-pressure, small-diameter pipelines that collect natural gas from the wellhead and transport it to processing or treating plants for processing, treating, and/or dehydration, for redelivery to larger diameter pipelines for further transportation to end-user markets.

Compression. Natural gas compression is a mechanical process in which gas at a lower pressure is boosted, or compressed, to a desired higher pressure, allowing the gas to flow into a higher-pressure, downstream pipeline where it will be transported to end-user markets. Field compression is typically used to lower the gas pressure at entry into the gathering system while maintaining or increasing the exit pressure, providing sufficient pressure to deliver gas into a higher-pressure, downstream pipeline.

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Dehydration. Dehydration is the process during which water is removed from the gas; also called Glycol Absorption.
Processing. Natural gas processing is the separation of natural gas into pipeline quality natural gas and a mixed NGL stream through either an absorption, mechanical or cryogenic process. The heavier components which make up the NGL stream are typically ethane, propane, isobutane, normal butane and natural gasoline.
Amine Treating. Natural gas treating entails the removal of impurities such as water, sulfur compounds, carbon dioxide and nitrogen. The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. The gas and amine are separated and the impurities are removed from the amine by heating. The treating plants are sized according to the amine circulation rate in terms of GPM.
Fractionation. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, normal butane, isobutane and natural gasoline. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of propylene and as a heating fuel, an engine fuel and an industrial fuel. Normal butane is used as a petrochemical feedstock in the production of butadiene (a key ingredient in synthetic rubber) and as a blend stock for motor gasoline. Isobutane is typically fractionated from mixed butane (a stream of normal butane and isobutane in solution), principally for use in enhancing the octane content of motor gasoline. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.
Transportation. Natural gas transportation consists of moving pipeline-quality natural gas from gathering systems, processing or treating plants and other pipelines and delivering it to wholesalers, end users, local distribution companies and other pipelines. Mixed NGLs are typically transported via NGL pipelines or by truck to fractionators, which separate the NGLs into their components.
Storage. A place to store natural gas supplies for use at a later time. Storage can be an old gas field, a developed salt dome or a liquefied natural gas tank.

INDUSTRY OUTLOOK

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—General Trends and Outlook”.

GATHERING AND PROCESSING OPERATIONS

General. We operate gathering and processing assets in four geographic regions of the United States: north Louisiana, the mid-continent region of the United States, south Texas and west Texas. We contract with producers to gather raw natural gas from individual wells or central receipt points, which may have multiple wells behind them, located near our processing plants, treating facilities and/or gathering systems. Following the execution of a contract, we connect wells and central receipt points to our gathering lines through which the raw natural gas flows to a processing plant, treating facility or directly to interstate or intrastate gas transportation pipelines. At our processing plants and treating facilities, we remove impurities from the raw natural gas stream and extract the NGLs. We also perform a producer service function, whereby we purchase natural gas from producers at gathering systems and plants and sell this gas at downstream outlets.

All raw natural gas flowing through our gathering and processing facilities is supplied under gathering and processing contracts having terms ranging from month-to-month to the life of the oil and gas lease. For a description of our contracts, read “—Our Contracts” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Our Operations.”

The pipeline-quality natural gas remaining after separation of NGLs through processing is either returned to the producer or sold, for our own account or for the account of the producer, at the tailgates of our processing plants for delivery to interstate or intrastate gas transportation pipelines.

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The following table sets forth information regarding our gathering systems and processing plants as of December 31, 2012:

Region	Pipeline Length (Miles)	Plants	Compression (Horsepower)
North Louisiana	653	6	120,399
South Texas	1,286	3	90,693
West Texas	941	2	52,670
Mid-Continent	3,465	1	29,742
Total	6,345	12	293,504

North Louisiana Region. Our north Louisiana assets gather, compress, treat and dehydrate natural gas in five Parishes (Claiborne, Union, DeSoto, Lincoln and Ouachita) of north Louisiana and Shelby County, Texas. Our assets also include two cryogenic natural gas processing facilities, a refrigeration plant located in Bossier Parish, a conditioning plant located in Webster Parish, an amine treating plant in DeSoto Parish, and an amine treating plant in Lincoln Parish.

In August 2012, we announced the construction of an expansion of the Dubach processing facility in North Louisiana that will increase the processing capacity of the facility to 210 MMcf/d by adding an incremental 70 MMcf/d of cryogenic processing capacity and 20 MMcf/d of JT capacity. The $75 million capital expenditure related to this expansion also includes the construction of high-pressure gathering lines to bring production to the facility. The project, which is expected to come online in the second quarter of 2013, is backed by fee-based contracts and an acreage dedication.

Through the gathering and processing systems described above and their interconnections with RIGS in north Louisiana described in “Natural Gas Transportation Operations,” we offer producers wellhead-to-market services, including natural gas gathering, compression, processing, treating and transportation.

South Texas Region. Our south Texas assets gather, compress, treat and dehydrate natural gas in LaSalle, Webb, Karnes, Atascosa, McMullen, Frio and Dimmitt counties. Some of the natural gas produced in this region can have significant quantities of hydrogen sulfide and carbon dioxide that require treating to remove these impurities. The pipeline systems that gather this gas are connected to third-party processing plants and our treating facilities that include an acid gas reinjection well located in McMullen County, Texas.

The natural gas supply for our south Texas gathering systems is derived from a combination of natural gas wells located in a mature basin that generally have long lives and predictable gas flow rates and the NGLs-rich Eagle Ford shale formation, which lies directly under our existing south Texas gathering system infrastructure.

One of our treating plants consists of inlet gas compression, a 60 MMcf/d amine treating unit, a 55 MMcf/d amine treating unit and a 40 ton (per day) liquid sulfur recovery unit. This plant removes hydrogen sulfide from the natural gas stream, recovers condensate, delivers pipeline quality gas at the plant outlet and reinjects acid gas. In January 2012, we completed an expansion of the treating plant, adding an incremental 20 MMcf/d of treating capacity to the facility.

In June 2011, we entered into agreements to provide gas and condensate gathering services for a producer in the Eagle Ford shale and to construct facilities to perform these services, including a wellhead gathering system, at an expected cost of approximately $450 million. The expansion will be owned and operated by us and will connect with our existing gathering system. The expansion is scheduled to be completed in phases by 2014. Upon its completion, our entire south Texas system will be capable of gathering, compressing, treating and transporting up to 1 Bcf/d of natural gas and 26,500 Bbls/d of condensate to downstream outlets.

We own a 60% interest in ELG that includes a treating plant in Atascosa County with a 500 GPM amine treater, pipeline interconnect facilities and approximately 13 miles of ten inch diameter pipeline. Talisman Energy USA Inc. and Statoil Texas Onshore Properties LP own the remaining 40% interest. We operate this plant and the pipeline for the joint venture while our joint venture partners operate a lean gas gathering system in the Edwards Lime natural gas trend that delivers to this system. In May 2012, we announced the construction of an expansion to ELG which will increase the system's capacity by 90 MMcf/d to 160 MMcf/d, and will provide for additional crude transportation and stabilization capacity of 17,000 Bbls/d. Contracts on the expansion are fee-based, which includes reservation fees. Capital expenditures related to the expansion are expected to total $150 million, of which we will contribute $90 million. The project is expected to be completed in mid-2013.

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West Texas Region. Our west Texas gathering system assets offer wellhead-to-market services to producers in Ward, Winkler, Reeves, and Pecos counties which surround the Waha Hub, one of Texas' developing NGLs-rich natural gas market areas. As a result of the proximity of our system to the Waha Hub, the Waha gathering system has a variety of market outlets for the natural gas that we gather and process, including several major interstate and intrastate pipelines serving California, the mid-continent region of the United States and Texas natural gas markets. The NGL market outlets include Lone Star's west Texas NGL pipeline.

We offer producers up to four different levels of natural gas compression on the Waha gathering system, as compared to the two levels typically offered in the industry. By offering multiple levels of compression, our gathering system is often more cost-effective for our producers, since the producer is typically not required to pay for a level of compression that is higher than the level they require.

The Waha processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered in the Waha gathering system. The Waha processing plant also includes an amine treating facility, which removes carbon dioxide and hydrogen sulfide from raw natural gas gathered before moving the natural gas to the processing plant. The acid gas is injected underground.

We also own a 33.33% membership interest in Ranch JV which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas. The joint venture owns a 25 MMcf/d refrigeration plant and a 100 MMcf/d cryogenic processing plant.

Mid-Continent Region. Our mid-continent systems are located in two large natural gas producing regions in the United States, the Hugoton Basin in southwest Kansas and the Anadarko Basin in western Oklahoma. These mature basins have continued to provide generally long-lived, predictable production volume. Our mid-continent gathering assets are extensive systems that gather, compress and dehydrate low-pressure gas from approximately 1,500 wells. These systems are geographically concentrated, with each central facility located within 90 miles of the others. We operate our mid-continent gathering systems at low pressures to maximize the total throughput volumes from the connected wells. Wellhead pressures are therefore adequate to allow for flow of natural gas into the gathering lines without the cost of wellhead compression.

We also own the Hugoton gathering system that has approximately 1,900 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.

NATURAL GAS TRANSPORTATION OPERATIONS

We own a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets.

We own a 50% membership interest in MEP. MEP owns an interstate natural gas pipeline with approximately 500 miles stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama.

We also own a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

NGL SERVICES OPERATIONS

We own a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including NGL pipelines, storage, fractionation and processing facilities located in Texas, Mississippi and Louisiana.

CONTRACT SERVICES OPERATIONS

Contract services operations can be divided into contract compression services and contract treating services. The natural gas contract compression services include designing, sourcing, owning, installing, operating, servicing, repairing and maintaining compressors and related equipment for which we guarantee our customers 98% mechanical availability for land installations and 96% mechanical availability for over-water installations. We focus on meeting the complex requirements of field-wide compression applications, as opposed to targeting the compression needs of individual wells within a field. These field-wide applications include compression for natural gas gathering and natural gas processing. We believe that we improve the stability of our cash flow by focusing on field-wide compression applications because such applications generally involve long-term installations of multiple large horsepower compression units. Our contract compression operations are primarily located in Texas, Louisiana, Arkansas, Pennsylvania, New Mexico and California.

We own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management. Our contract treating services are primarily located in Texas, Louisiana and Arkansas.

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CORPORATE OPERATIONS

Our Corporate segment comprises our corporate offices.

OUR CONTRACTS

The table below provides the margin by product in percentages for the years ended December 31, 2012 and 2011 for all of our operating segments including our proportional shares in our unconsolidated affiliates:

Margin by Product	2012		2011	
Net Fee	84	%	83	%
NGLs	7		9	
Gas	3		5	
Condensate	6		3	
Total	100	%	100	%

Gathering and Processing Contracts. We contract with producers to gather raw natural gas from individual wells or central receipt points located near our gathering systems and processing plants. Following the execution of a contract with the producer, we connect the producer's wells or central receipt points to our gathering lines through which the natural gas is delivered to a processing plant owned and operated by us or a third party. We obtain supplies of raw natural gas for our gathering and processing facilities under contracts having terms ranging from month-to-month to life of the lease. We categorize our processing contracts in increasing order of commodity price risk as fee-based, percentage-of-proceeds or keep-whole contracts. The following is a summary of our most common contractual arrangements:

- Fee-Based Arrangements. Under these arrangements, we are generally paid a fixed cash fee for performing the gathering and processing service. This fee is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. A sustained decline in commodity prices, however, could result in a decline in volumes and, thus, a decrease in our fee revenues. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments.
- Percent-of-Proceeds Arrangements. Under these arrangements, we generally gather raw natural gas from producers at the wellhead or central receipt points, transport it through our gathering system, process it and sell the processed gas and NGLs at prices based on published index prices. In this type of arrangement, we retain the sales proceeds less amounts remitted to producers and the retained sales proceeds constitute our margin. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. Under these arrangements, our margins typically cannot be negative. The price paid to producers is based on an agreed percentage of one of the following: (1) the actual sale proceeds; (2) the proceeds based on an index price; or (3) the proceeds from the sale of processed gas or NGLs or both. Under this type of arrangement, our margin correlates directly with the prices of natural gas and NGLs (although there is often a fee-based component to these contracts in addition to the commodity sensitive component).
- Keep-Whole Arrangements. Under these arrangements, we process raw natural gas to extract NGLs and pay to the producer the full thermal equivalent volume of raw natural gas received from the producer in processed gas or its cash equivalent. We are generally entitled to retain the processed NGLs and to sell them for our account. Accordingly, our margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the thermal equivalent value of those NGLs. The profitability of these arrangements is subject not only to the commodity price risk of natural gas and NGLs, but also to the price of natural gas relative to NGL prices. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. Many of our keep-whole contracts include provisions that reduce our commodity price exposure, including (1) embedded discounts to the applicable natural gas index price under which we may reimburse the producer an amount in cash for the thermal equivalent volume of raw natural gas acquired from the producer, (2) fixed cash fees for ancillary services, such as gathering, treating, and compression, or (3) the ability to bypass processing in unfavorable price environments.

We also perform a producer service function. We purchase natural gas from producers or gas marketers at receipt points or plant tailgates, including points on HPC's RIGS, and we sell the natural gas to other market participants, often after transporting the gas to delivery points on HPC's RIGS or other transportation pipeline systems.

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Natural Gas Transportation Contracts. We own a 49.99% general partner interest in HPC and a 50% membership interest in MEP. HPC and MEP, through their respective pipeline systems, provide natural gas transportation services pursuant to contracts with natural gas shippers. These contracts are primarily fee-based. HPC's long-term firm transportation contracts will expire between 2013 and 2022; and MEP's long-term firm service agreements will expire between 2013 and 2021.

NGL Services Contracts. We own a 30% membership interest in Lone Star. Lone Star owns and operates approximately 1,740 miles of NGL pipelines including the newly constructed 570-mile West Texas Gateway NGL Pipeline that was placed in service ahead of schedule in December 2012, two cryogenic refinery off-gas processing plants, one fractionation facility which came online in December 2012 with a capacity of 100,000 Bbls/d, and two NGL storage facilities with aggregate working storage capacity of approximately 47 million Bbls. Lone Star also has a non-operating interest in an additional cryogenic processing plant. Revenue is principally generated from fees charged to customers under dedicated contracts, take-or-pay contracts and commodity pricing. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

Compression Contracts. We generally enter into a new contract with respect to each distinct application for which we will provide contract compression services. Our compression contracts typically have an initial term between one and five years, after which the contract continues on a month-to-month basis until renewal or cancellation. Our customers generally pay a fixed monthly fee, or, in rare cases, a fee based on the volume of natural gas actually compressed. We are not responsible for acts of force majeure and our customers are generally required to pay our monthly fee for fixed fee contracts, or a minimum fee for throughput contracts, even during periods of limited or disrupted production. We are generally responsible for the costs and expenses associated with operation and maintenance of our compression equipment, such as providing necessary lubricants, although certain fees and expenses are the responsibility of the customers under the terms of their contracts. For example, all fuel gas is provided by our customers without cost to us, and in many cases customers are required to provide all water and electricity. We also are reimbursed by our customers for certain ancillary expenses such as trucking, crane and installation labor costs, depending on the terms agreed to in a particular contract.

Treating Contracts. Our treating contracts are application specific, having an initial term between one and three years, after which the contract continues on a month-to-month basis. Our customers generally pay a fixed monthly fee that not only includes the amine plant, but may also include additional equipment as required by the application. We are not responsible for acts of force majeure and our customers are generally required to pay our monthly fee even during periods of limited or disrupted production. We are generally responsible for the costs and expenses associated with the operation and maintenance of our treating equipment, such as providing the necessary makeup fluids, filters and charcoal. However, our customers are typically responsible for all fuel, gas and electricity without cost to us. Our fees include costs for all mobilization, installation, commissioning and startup.

COMPETITION

Gathering and Processing. We face strong competition in each region in acquiring new gas supplies. Our competitors in acquiring new gas supplies and in processing new natural gas supplies include major integrated oil companies, major interstate and intrastate pipelines and other natural gas gatherers that gather, process and market natural gas. Competition for natural gas supplies is primarily based on the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer.

Many of our competitors have capital resources and control supplies of natural gas substantially greater than ours. Our major competitors for gathering and related services in each region include:

- North Louisiana: CenterPoint Energy Field Services and DCP Midstream's PELICO Pipeline, LLC (Pelico), ETP, KMP and Chesapeake Midstream Partners, L.P.;
- South Texas: Enterprise Products Partners LP, DCP Midstream Partners, L.P, KMP, ETP and Copano Energy, L.L.C;
- West Texas: Southern Union Gas Services, Enterprise Products Partners LP and Targa Resources Partners L.P.; and
- Mid-Continent: DCP Midstream Partners, L.P., ONEOK Partners L.P. and PVR Partners, L.P.

Natural Gas Transportation. We own a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets. Competitors in natural gas transportation differentiate themselves by the price of transportation, the nature of the markets accessible from a transportation pipeline and the type of service provided. HPC's major competitors in the natural gas transportation business are DCP Midstream Partners, L.P., CenterPoint Energy Transmission, Gulf South Pipeline, L.P., Texas Gas Transmission, LLC, ETP and Enterprise Products Partners LP.

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We own a 50% membership interest in MEP, which owns the approximate 500-mile Midcontinent Express natural gas pipeline system. An affiliate of KMP owns a 50% interest in MEP and acts as the operator of MEP. Capacity on the MEP pipeline system is 99% contracted under long-term firm service agreements. The majority of volume is contracted to producers moving supply from the Barnett shale and Oklahoma supply basins. These agreements provide the pipeline with fixed monthly reservation revenues for the primary term of such contracts. Although there are other pipeline competitors providing transportation from these supply basins, the MEP pipeline system was designed and constructed to realize economies of scale and offers its shippers competitive fuel rates and variable costs to transport gas supplies from these midcontinent supply areas to pipelines serving Eastern markets. MEP's competitors include Gulf Crossing Pipeline, Centerpoint Energy Gas Transmission and Natural Gas Pipeline Co. of America.

NGL Services. We own a 30% membership interest in Lone Star which owns and operates approximately 1,740 miles of NGL pipelines, two cryogenic refinery off-gas processing plants, one fractionation facility, two NGL storage facilities and has a non-operating interest in an additional cryogenic processing plant. In markets served by its NGL pipelines, Lone Star competes with other pipeline companies and barge, rail and truck fleet operations. Lone Star also faces competition with other fractionation and storage facilities based on fees charged and the ability to receive and distribute the customer's products. Lone Star's main competitors include Enterprise Products Partners, L.P., DCP Midstream Partners, LP and ONEOK Partners, L.P.

Contract Services. Our contract services operation includes contract compression and contract treating. We believe that the superior mechanical availability of our standardized compressor fleet is the primary basis on which we compete and a significant distinguishing factor from our competition. All of our competitors attempt to compete on the basis of price. We believe our pricing is competitive because of the superior mechanical availability we deliver, the quality of our compression units, as well as the technical expertise we provide to our customers. We believe our focus on addressing customers' more complex natural gas compression needs related primarily to field-wide compression applications differentiates us from many of our competitors who target smaller horsepower projects related to individual wellhead applications. The natural gas contract compression services business is highly competitive. We face competition from large national and multinational companies and, on a regional basis, from numerous smaller companies. Our main competitors in the natural gas contract compression business, based on horsepower, are Exterran Holdings, Inc., Compressor Systems, Inc., USA Compression, Valerus Compression Services LP, and J-W Energy Company.

The natural gas treating business is highly competitive. We face competition from large national and multinational companies with greater financial resources and, on a regional basis, from numerous smaller companies. Our main competitors in the natural gas treating business are KMP, Valerus Compression Services LP, TransTex Gas Services, LP, Cardinal Midstream LLC, SouthTex Treaters, Interstate Treating Inc., Exterran Holdings, Inc., Thomas Russell Co. and Spartan Energy Group.

RISK MANAGEMENT

To manage commodity price and interest rate risks, we have implemented a risk management program under which we seek to:

- match sales prices of commodities (especially NGLs) with purchases under our contracts;
- manage our portfolio of contracts to reduce commodity price risk;
- optimize our portfolio by active monitoring of basis, swing, and fractionation spread exposure; and
- hedge a portion of our exposure to commodity prices.

As a result of our gathering and processing contract portfolio, we derive a portion of our earnings from a long position in NGLs, natural gas and condensate, resulting from the purchase of natural gas for our account or from the payment of processing charges in kind. This long position is exposed to commodity price fluctuations in the condensate, NGLs and natural gas markets. Operationally, we mitigate this price risk by generally purchasing natural gas and NGLs at prices derived from published indices, rather than at a contractually fixed price and by selling natural gas and NGLs under similar pricing mechanisms. In addition, we optimize the operations of our processing facilities on a daily basis, for example by rejecting ethane in processing when recovery of ethane as an NGL is uneconomical. We hedge this commodity price risk by entering into a series of swap contracts or put option contracts for individual NGLs, natural gas and WTI. Our hedging positions are maintained within limits established by the Audit and Risk Committee of the Board of Directors. Read “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for information regarding the status of these contracts. As a matter of policy, we do not acquire forward contracts or derivative products for the purpose of speculating on price changes.

Neither our contract compression business nor our contract treating business has direct exposure to natural gas commodity price risk because we do not take title to the natural gas we compress or treat and because the natural gas we use as fuel for our compressors is supplied by our customers or treating units without cost to us.

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REGULATION

Industry Regulation

Intrastate Natural Gas Pipeline Regulation. HPC owns RIGS, an intrastate pipeline regulated by the Louisiana Department of Natural Resources, Office of Conservation (DNR). The DNR is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. RIGS transports interstate natural gas in Louisiana for many of its shippers pursuant to Section 311 of the NGPA. To the extent that RIGS transports natural gas in interstate service, its rates and terms and conditions of service are subject to the jurisdiction of FERC, including its non-discrimination requirements. FERC has substantial enforcement authority to impose administrative, civil and criminal penalties of up to $1 million per day per violation and to order the disgorgement of unjust profits for non-compliance.

Under Section 311 of the NGPA, rates charged for transportation services must be fair and equitable. FERC approved RIGS' NGPA Section 311 rates as fair and equitable effective February 1, 2010, under a settlement. As part of the settlement and consistent with FERC policy, RIGS is required to justify its current rates or propose new rates every five years. Accordingly, RIGS must make a rate filing on or before February 1, 2015. At that that time, RIGS' rates will be in effect, but subject to refund with interest until FERC has determined that the rates are fair and equitable. FERC continually proposes and implements new rules and regulations affecting Section 311 transportation. For example, on October 21, 2010, the FERC issued a Notice of Inquiry regarding the applicability of the FERC's buy-sell rules to intrastate pipelines that provide Section 311 transportation service, including whether the FERC should impose capacity release requirements on such pipelines that offer firm transportation service. We cannot predict the outcome of this notice of inquiry or other regulatory changes that may be proposed or enacted, but any changes could lead to greater regulatory requirements on intrastate pipelines that provide Section 311 services, including RIGS.

Interstate Natural Gas Pipeline Regulation. FERC also has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the NGA, rates charged for interstate natural gas transmission must be just and reasonable. Gulf States and MEP hold FERC-approved tariffs setting forth cost-based rates and terms and conditions of service for shippers wishing to secure capacity for interstate transportation service. Rates charged on MEP are largely governed by long-term negotiated rate agreements, an arrangement approved by FERC in its July 25, 2008 order granting MEP the certificate of public convenience and necessity to build, own and operate these facilities. MEP and Gulf States are NGA-jurisdictional interstate pipelines subject to FERC's broad regulatory oversight. FERC's authority extends to:

- rates and charges for natural gas transportation and related services;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between the pipeline and its energy affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- accounting rules for ratemaking purposes;
- acquisition and disposition of facilities;
- initiation and discontinuation of service;
- prevention of market manipulation in connection with interstate sales, purchase or transportation of natural gas; and
- information posting requirements.

FERC regularly conducts audits of interstate pipelines and has multiple means to receive complaints of alleged violations of its rules, including anonymous complaints through a toll-free hotline. Any failure to comply with the laws and regulations governing interstate transportation service could result in the imposition of significant administrative, civil and criminal penalties. FERC has authority to impose civil penalties of up to $1 million per day per violation.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from FERC jurisdiction under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests that

FERC has used to establish a pipeline's status as a gatherer not subject to FERC's interstate pipeline jurisdiction. The distinction between FERC-regulated

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transmission facilities and federally unregulated gathering facilities is the subject of substantial, on-going litigation none of which we are currently party to. As a result, the classification and regulation of one or more of our gathering systems may be subject to change based on future determinations by FERC, the courts or the U.S. Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and, in other instances, complaint-based rate regulation. We are subject to state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers that purchase gas to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another or one source of supply over another. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

In addition, many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules, ordinances and legislation pertaining to these matters may be considered or adopted from time to time at either the federal, state or local level. We cannot predict what effect, if any, such changes might have on our operations, but we and our competitors could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Regulation of NGL and Crude Oil Transportation. We have a pipeline in Louisiana that transports NGLs in interstate commerce pursuant to a FERC-approved tariff. Under the ICA, the Energy Policy Act of 1992, and rules and orders promulgated thereunder, the transportation tariff is required to be just and reasonable and not unduly discriminatory or confer any undue preference. FERC has established an indexing system of transportation rates for oil, NGLs and other products that allows for an annual inflation based increase in the cost of transporting these liquids to shipper. Any failure on our part to comply with the laws and regulations governing interstate transmission of NGLs could result in the imposition of administrative, civil and criminal penalties and could have a material adverse effect on our results of operations.

Lone Star has pipelines that transport NGLs in intrastate commerce pursuant to state common carrier regulation. We also have or are constructing pipelines that are subject to state common carrier regulation for the transportation of NGLs, crude oil or condensate. Under state common carrier regulation, pipelines must charge rates that are non-discriminatory and operate pursuant to a tariff.

Sales of Natural Gas and NGLs. Our ability to sell gas in interstate markets is subject to FERC authority and oversight. The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The price at which we sell NGLs is not subject to state or federal regulation. However, with regard to our physical purchases and sales of these energy commodities, our gathering or transportation of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC.

The prices at which we sell natural gas are affected by many competitive factors, including the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. Additionally, FERC imposed rules requiring wholesale purchasers and sellers of natural gas to report certain aggregated annual volume and other information beginning in 2009. On November 15, 2012, FERC issued a Notice of Inquiry seeking comments on whether reporting should be expanded to include more frequent and detailed information about certain interstate natural gas sales transactions. We cannot predict the outcome of this Notice of Inquiry or other regulatory changes that may be proposed or enacted.

We also have firm and interruptible transportation contracts with interstate pipelines that are subject to FERC regulation. As a shipper on an interstate pipeline, we are subject to FERC requirements related to use of interstate capacity. Any failure on our part to comply with the FERC's regulations or an interstate pipeline's tariff could result in the imposition of administrative, civil and criminal penalties and the disgorgement of unjust profits.

Sales of crude oil, natural gas, condensate and NGLs are not currently regulated. Prices of these products are set by the market rather than by regulation.

Anti-Market Manipulation Requirements. Under the Energy Policy Act of 2005, FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. The CFTC also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. With regard to our physical purchases and sales of natural gas, NGLs and crude oil,

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our gathering (of natural gas) or transportation of these energy commodities, and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation in connection with the sale, purchase or transportation of natural gas, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, or among others, sellers, royalty owners and taxing authorities.

Anti-Terrorism Regulations. We may be subject to future anti-terrorism requirements of the DHS. The DHS has issued its National Infrastructure Protection Plan calling for broadened efforts to “reduce vulnerability, deter threats, and minimize the consequences of attacks and other incidents” as they relate to pipelines, processing facilities and other infrastructure. The precise parameters of DHS regulations and any related sector-specific requirements are not currently known, and there can be no guarantee that any final anti-terrorism rules that might be applicable to our facilities will not impose costs and administrative burdens on our operations.

Eminent Domain. Gas utilities, common carrier pipelines, intrastate pipelines and interstate pipelines typically have eminent domain authority granted by the state or federal government. These eminent domain rights are often subject to public scrutiny, lawsuits and regulatory and/or legislative review. In 2011, the Texas Supreme Court issued a decision impacting the ability of common carriers to acquire land through the use of eminent domain. Certain components of the decision were clarified in 2012; however, as a result of the decision common carrier pipelines could be required to prove “public use” separately in each condemnation proceeding along the entire route of a pipeline. The decision could impact our ability to acquire right-of-way using condemnation for the construction of new common carrier pipeline projects in the state of Texas. Any new court decisions or changes to eminent domain laws or regulations could alter our ability to acquire pipeline right-of-way utilizing eminent domain.

Local Laws and Regulations. With the rapid expansion of natural gas development in shale plays, local governmental authorities are seeking to impose additional regulatory requirements on natural gas market participants, including producers, gatherers, and pipeline companies, which may result in additional cost burdens and permitting requirements for new and existing facilities.

Environmental Matters

General. Our operation of processing plants, pipelines and associated facilities, including compression, in connection with the gathering, treating and processing of natural gas and the transportation of NGLs is subject to stringent and complex federal, state and local laws and regulations, including those governing, among other things, operation of gas injection wells, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and other criminal sanctions, third party claims for personal injury or property damage, investments to retrofit or upgrade our facilities and programs, or curtailment of operations. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall cost of doing business, including our cost of planning, constructing and operating our plants, pipelines and other facilities. Included in our construction and operation costs are capital cost items necessary to maintain or upgrade our equipment and facilities to remain in compliance with environmental laws and regulations.

We have implemented procedures to ensure that all governmental environmental approvals for both existing operations and those under construction are updated as circumstances require. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our business, results of operations and financial condition. We cannot be certain, however, that identification of presently unidentified conditions, more rigorous enforcement by regulatory agencies, enactment of more stringent laws and regulations or other unanticipated events will not arise in the future and give rise to material environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

Hazardous Substances and Waste Materials. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances and waste materials into soils, groundwater and surface water and include measures to prevent, minimize or remediate contamination of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of hazardous substances and waste materials and may require investigatory and remedial actions at sites where such material has been released or disposed. For example, CERCLA, also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. These persons include the owner and operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substance that has been released into the environment. Under CERCLA, these persons may be subject to joint and several liability, without regard to fault, for, among other things, the costs of investigating and remediating the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and comparable state law also authorize the federal EPA, its state counterparts, and, in some instances, third parties to take actions in response to threats

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to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Although "petroleum" as well as natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations we generate wastes or other materials that may fall within that definition or that may be subject to other waste disposal laws and regulations. We may be responsible under CERCLA or state laws for all or part of the costs required to clean up sites at which such substances or wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or comparable state laws.

We also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal RCRA, and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements at many of our facilities because the minimal quantities of hazardous wastes generated there make us subject to less stringent management standards. From time to time, the EPA has considered the adoption of stricter handling, storage and disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. It is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense.

We currently own or lease sites that have been used over the years by prior owners and by us for natural gas gathering, processing and transportation. Solid waste disposal practices within the midstream gas industry have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and wastes have been disposed of or released on or under various sites during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these dispositions may have occurred during the ownership of these assets by others, these sites may be subject to CERCLA, RCRA and comparable state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or contamination (including soil and groundwater contamination) or to prevent the migration of contamination.

Air Emissions. Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, such as our processing plants and compression facilities, expected to produce air emissions or to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. We will be required to incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, our processing plants, pipelines and compression facilities are subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. We believe that our operations are in substantial compliance with the federal Clean Air Act and comparable state laws. The EPA and state agencies are continually proposing new rules and regulations that could impact our existing operations and the costs and timing of new infrastructure development.

Specifically, the EPA has finalized a set of rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. The rule package includes revised new source performance standards (NSPS) to address volatile organic compounds (VOCs) and sulfur dioxide emissions at natural gas processing plants. The final rules require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process.

The rules also establish specific requirements regarding emissions from compressors, pneumatic controllers, dehydrators, storage tanks and other production equipment. In addition, the rules specify revised and more stringent leak detection requirements for natural gas processing plants. These rules will require a number of modifications to our operations, including the installation of new equipment, although the compliance deadline for some of these rules is deferred until January 1, 2015 and other requirements will apply only to facilities that are newly constructed, reconstructed, or substantially modified. We are still evaluating the effect of these rules on our operations, but we expect that they could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business.

On October 19, 2010, the EPA adopted new national emission standards for hazardous air pollutants for existing stationary spark ignition reciprocating internal combustion engines that are either located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions. All engines subject to these “Quad Z” regulations are required to comply by October 19, 2013. Many of our facilities,

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including our leased compressors are impacted by these new rules. We will incur increased costs resulting from the replacement of existing equipment to bring engines into compliance with the new emission requirements. Petitions have been filed in the court of appeals for review and reconsideration of the new rules, but we cannot predict the outcome of those proceedings.

2008 Ozone NAAQS Designations. EPA Region 6 is proposing to modify the Governor of Texas' recommended designations for the 2008 ozone National Ambient Air Quality Standards (”NAAQS”). EPA's proposal expands the Dallas-Ft Worth and Houston-Galveston-Brazoria Counties nonattainment areas to include three additional counties. If EPA's proposal is adopted, the state of Texas will be under an obligation to develop a state implementation plan to control new and existing sources of ozone precursor emissions in those counties, which would significantly increase the cost of operations in those counties. In addition, new sources would be required to offset emissions and the major source threshold for construction permits would be lower than otherwise, triggering more stringent control technology and impacts reviews.

New TCEQ Rule. On January 26, 2011, the TCEQ adopted a new Section 106.352. Oil and Gas Handling and Production Facilities Permit by Rule (“PBR”), which is applicable to oil and gas facilities in the Barnett shale area of Texas and provides an authorization for activities that produce more than a de minimis level of emissions. The PBR requires additional recordkeeping and reporting requirements, additional best management practices, increased emissions modeling, increased stack testing and an increase in project/facility registrations, all of which would increase our capital and operating costs in the Barnett shale in Texas. Additionally, only one PBR may be claimed or registered for each combination of dependent facilities at an oil and gas site, which is defined as all facilities that are located on contiguous or adjacent properties, under common control and designated under the same two digit standard industrial classification (”SIC”) code. The construction of new facilities or modification of existing facilities at an oil and gas site will subject the existing, operationally-dependent, unmodified facilities to a protectiveness review and to emissions limits for its planned maintenance, startup and shutdown activities, which may require the installation of additional emissions control equipment thereby increasing the costs of new projects and increasing capital expenditures in the Barnett shale in Texas. Currently, our facilities located in the Barnett shale are part of our Contract Services Segment, and most compliance costs resulting from the PBR will be borne by our customers. Oil and gas handling and production facilities not located in the Barnett shale regions remain subject to the provisions of the PBR that was in place prior to the adoption of new Section 106.352.

Clean Water Act. The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including NGL-related wastes, into waters of the United States. Pursuant to the Clean Water Act and similar state laws, a NPDES, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that our continued compliance with such existing permit conditions will not have a material adverse effect on our business, financial condition or results of operations.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitat. We may operate in areas that are currently designated as a habitat for endangered or threatened species, the discovery of previously unidentified endangered species, or the designation of additional species as endangered or threatened, which could cause us to incur additional costs, to develop habitat conservation plans, to become subject to expansion or operating restrictions, or bans in the affected areas.

Climate Change. On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA adopted two sets of regulations addressing greenhouse gas emissions under the Clean Air Act. The first limits emissions of greenhouse gases from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle greenhouse gas emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to "best available control technology" standards for greenhouse gases, which are currently being developed on a case-by-case basis. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce or sequester emissions of greenhouse gases associated with our operations and also could adversely affect demand for the natural gas and other hydrocarbon products that we transport, process, or otherwise handle in connection with our services.

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In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. On November 30, 2010, the EPA revised its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Under the new rules, reporting of greenhouse gas emissions from such facilities, including many of our facilities, is required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

Various pieces of legislation to reduce emissions of, or to create cap and trade programs for, greenhouse gases have been proposed by the U.S. Congress over the past several years, but no proposal has yet passed. More than one-third of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our own operations, and it could also adversely affect demand for our transportation, storage and midstream services.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our NGLs and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term “global warming” as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

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

Safety Regulations. Those pipelines through which we transport mixed NGLs (exclusively to other NGL pipelines) are subject to regulation by the DOT, under the HLPSA, relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA requires any entity that owns or operates liquids pipelines to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to submit certain reports and provide other information as required by the Secretary of Transportation. We believe our liquids pipelines are in substantial compliance with applicable HLPSA requirements. The DOT is continually proposing new pipeline safety rules that may impact our businesses and increase our operating costs.

Our interstate, intrastate and certain of our gathering pipelines are also are subject to regulation by the DOT under the NGPSA, which covers natural gas, crude oil, carbon dioxide, NGLs and petroleum products pipelines, and under the Pipeline Safety Improvement Act of 2002, as amended. Pursuant to these authorities, the DOT has established a series of rules that require pipeline operators to develop and implement “integrity management programs” for natural gas pipelines located in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. Similar rules are also in place for operators of hazardous liquid pipelines. The DOT's integrity management rules establish requirements relating to the design, installation, testing, construction, operation, inspection, replacement and management of pipeline facilities. We believe that our pipeline operations are in substantial compliance with applicable NGPSA requirements.

The DOT enacted new control room management regulations as directed by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The rules require operators of hazardous liquids pipelines, gas pipelines and LNG facilities with at least one control room to develop and implement written control room management procedures. We believe we are in substantial compliance with the new rules as of the required compliance date of August 1, 2011.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, became effective. Under the new law, the DOT and other federal agencies are required to conduct a number of studies or develop rules over the next two years regarding the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related rules. The new law also increases civil penalties for violations, The DOT has already sought comments on potential rules that address many areas of the newly adopted legislation. Any new regulations could impact our businesses and increase our operating costs.

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The states administer federal pipeline safety standards under the NGPSA and have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, the DOT and individual states may pass additional pipeline safety requirements, but such requirements, if adopted, would not be expected to affect us disproportionately relative to other companies in our industry.

EMPLOYEES

As of December 31, 2012, our General Partner employed 781 employees, of whom 643 were field operating employees and 138 were mid-and senior-level management and staff. None of these employees are represented by a labor union and there are no outstanding collective bargaining agreements to which our General Partner is a party. Our General Partner believes that it has good relations with its employees.

AVAILABLE INFORMATION

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the SEC. From time to time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. In addition, the SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We make our SEC filings available to the public, free of charge and as soon as practicable after they are filed with the SEC, through its Internet website located at http://www.regencyenergy.com. Our annual reports are filed on Form 10-K, our quarterly reports are filed on Form 10-Q and current-event reports are filed on Form 8-K; we also file amendments to reports filed or furnished pursuant to Section 13(a) or Section 15(d) of the Exchange Act. References to our website addressed in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, our website. Therefore, such information should not be considered part of this report.

Item 1A. Risk Factors

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our business, our structure as a limited partnership and our tax treatment could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. These are not all of the risks we face as there are other factors currently considered immaterial or unknown to us that may impact our future operations.

RISKS RELATED TO OUR BUSINESS

We may not have sufficient cash from operations to enable us to pay our current quarterly distribution following the establishment of cash reserves and payment of fees and expenses, including reimbursement of fees and expenses of our General Partner.

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

- prevailing economic conditions;
- the fees we charge and the margins we realize for our services and sales;
- the prices of, level of, production of, and demand for natural gas and NGLs;
- the volumes of natural gas we gather, process and transport; and
- the amounts of our operating costs, including reimbursement of fees and expenses of our General Partner.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- our debt service requirements;
- our obligation to pay distributions on our Series A Preferred Units;
- fluctuation in our working capital needs;
- our ability to borrow funds and access capital markets;

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- restrictions contained in our debt agreements;
- the cost of acquisitions, if any;
- the amounts of cash reserves established by our General Partner; and
- our ability to maintain commodity hedge prices from year to year.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, not net income (loss) per GAAP. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not be able to make cash distributions during periods when we record net earnings for financial accounting purposes.

Our cash flow is affected by supply and demand for natural gas and NGL products and by natural gas and NGL prices, and decreases in these prices could adversely affect our results of operations and financial condition. Natural gas, NGLs and other commodity prices are volatile, and an unfavorable change in these prices could adversely affect our cash flow and operating results.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. NGLs prices generally fluctuate on a basis that correlates to fluctuations in crude oil prices as well as global demand of petrochemical products. In the past, the prices of natural gas, NGLs and crude oil have been extremely volatile, and this volatility could continue. Volatility in crude oil, natural gas and NGL prices can impact our customers' activity levels and spending for our products and services, as well as our margins under our keep-whole and percentage-of-proceeds natural gas gathering and processing contracts. The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for crude oil, natural gas and NGLs, which fluctuates with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for crude oil, natural gas and NGLs;
- the level of domestic crude oil and natural gas production;
- the availability of imported crude oil, natural gas and NGLs;
- actions taken by foreign crude oil and gas producing nations;
- the availability of local transportation systems;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Our natural gas gathering and processing businesses operate under two types of contractual arrangements that expose our cash flows to increases and decreases in the price of natural gas and NGLs: percentage-of-proceeds and keep-whole arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers and retain from the sale an agreed percentage of pipeline-quality gas and NGLs resulting from our processing activities (in cash or in-kind) at market prices. Under keep-whole arrangements, we receive the NGLs removed from the natural gas during our processing operations as the fee for providing our services in exchange for replacing the thermal content removed as NGLs with a like thermal content in pipeline-quality gas or its cash equivalent. Under these types of arrangements our revenues and our cash flows increase or decrease as the prices of natural gas and NGLs fluctuate. The relationship between natural gas prices and NGL prices may also affect our profitability. When natural gas prices are low relative to NGLs prices, it is more profitable for us to process natural gas under keep-whole arrangements. When natural gas prices are high relative to NGLs prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and of the increased cost (principally that of natural gas as a feedstock and a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed at some of our plants.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new supplies of natural gas, which involves factors beyond our control. Any decrease in supplies or the price of natural gas in our areas of operation could adversely affect our business and operating results.

Our gathering and processing and transportation pipeline systems are dependent on the level of production from natural gas wells that supply our systems and from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput volume levels on our gathering and transportation pipeline systems and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and attract new customers to our assets are: the level of successful drilling activity near our systems and our ability to compete with other gathering and processing companies for volumes from successful new wells.

The level of natural gas drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is natural gas prices. A sustained decline in natural gas prices, as has occurred over the past year, could result in a decrease in exploration and development activities in the fields served by our gathering and processing facilities and pipeline transportation systems, which would lead to reduced utilization of these assets. Some producers have indicated that they will focus their exploration and production efforts on geographic areas with oil and NGL-rich natural gas products. Other factors that impact production decisions include producers' capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes.

Because of these factors, even if additional natural gas reserves were discovered in areas served by our assets, producers may choose not to develop those reserves. If we were not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, throughput volumes on our pipelines and the utilization rates of our processing facilities would decline, which could have a material adverse effect on our business, results of operations and financial condition.

Our natural gas contract compression operations significantly depend upon the continued demand for and production of natural gas and crude oil. Demand may be affected by, among other factors, natural gas prices, crude oil prices, weather, demand for energy, and availability of alternative energy sources. Any prolonged, substantial reduction in the demand for natural gas or crude oil would, in all likelihood, depress the level of production activity and result in a decline in the demand for our contract compression services and products. Lower natural gas prices or crude oil prices over the long-term could result in a decline in the production of natural gas or crude oil, respectively, resulting in reduced demand for our natural gas contract compression services. Additionally, production from natural gas sources such as longer-lived tight sands, shales and coalbeds constitute an increasing percentage of our compression services business. Such sources are generally less economically feasible to produce in lower natural gas price environments, and a reduction in demand for natural gas may cause such sources of natural gas to be uneconomic to drill and produce, which could in turn negatively impact the demand for our compression services.

The profitability of certain activities in our NGLs and refined products storage business, our NGLs transportation business and our off-gas processing and fractionating business are largely dependent upon market demand for NGLs and refined products, which has been volatile, and competition in the market place, both of which are factors that are beyond our control.

Our NGLs and refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers. However, a portion of our revenues are derived from fungible storage and throughput arrangements, under which our revenues are more dependent upon demand for storage from our customers. Demand for these services may fluctuate as a result of changes in commodity prices. Our NGLs and refined products storage assets are primarily located in the Mont Belvieu area, which is a significant storage distribution and trading complex with multiple industry participants, any one of which could compete for the business of our existing and potential customers. Any loss of business from existing customers or our inability to attract new customers could have an adverse effect on our results of operations.

Revenues from our NGLs transportation systems are exposed to risks due to fluctuations in demand for transportation as a result of unfavorable commodity prices and competition from nearby pipelines. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. We may not be able to renew these contracts or execute new customer contracts on favorable terms if NGLs prices decline and demand for our transportation services decreases. Any loss of existing customers due to decreased demand for our services or competition from other transportation service providers could have a negative impact on our revenues and have an adverse effect on our results of operations.

Revenues from our off-gas processing and fractionating system in south Louisiana are exposed to risks due to the low concentration of suppliers near our facilities and the possibility that connected refineries may not provide us with sufficient off-gas for processing at our facilities. The connected refineries may also experience outages due to maintenance issues and severe weather, such as hurricanes. We receive revenues primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenues are exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

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Many of our customers' drilling activity levels and spending for transportation on our gathering and pipeline systems may be impacted by commodity prices and the credit markets.

Many of our customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Any combination of a reduction of cash flow resulting from declines in natural gas prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' spending for natural gas drilling activity, which could result in lower volumes being transported on our gathering and pipeline systems. A significant reduction in drilling activity could have a material adverse effect on our operations.

We depend on certain key producers and other customers for a significant portion of our supply of natural gas, contract compression and contract treating revenues. The loss of, or reduction in, any of these key producers or customers could adversely affect our business and operating results.

We rely on a limited number of producers and other customers for a significant portion of our natural gas supplies and our contracts for compression services. These contracts have terms that range from month-to-month to life of lease. As these contracts expire, we will have to negotiate extensions or renewals or replace the contracts with those of other suppliers. We may be unable to obtain new or renewed contracts on favorable terms, if at all. The loss of all or even a portion of the volumes of natural gas supplied by these producers and other customers, as a result of competition or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

We do not control all of the actions by our joint ventures.

Our joint ventures, including HPC, MEP, Lone Star and Ranch JV, have their own governing boards. We exercise some influence over the joint ventures because our approval is required for most significant decisions, but we do not control all of the decisions of these boards.

We may be required to make additional capital contributions to our equity joint ventures.

All of our equity joint ventures may request that we make additional capital contributions to support their capital expenditure programs. If such capital contributions are required, we may not be able to obtain the financing necessary to satisfy our obligations. In the event that we elect not to participate in future capital contributions, our ownership interest in the joint ventures will be diluted.

The contract compression business within our Contract Services segment depends on particular suppliers and is vulnerable to parts and equipment shortages and price increases, which could have a negative impact on our results of operations.

The principal manufacturers of components for our natural gas compression equipment include Caterpillar, Inc. for engines, Air-X-Changers for coolers, and Ariel Corporation for compressors and frames. Our reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. We also rely primarily on one vendor, Standard Equipment Corp., a subsidiary of ETP, to package and assemble our compression units. We do not have long-term contracts with these suppliers or packagers, and a partial or complete loss of certain of these sources could have a negative impact on our results of operations and could damage our customer relationships. In addition, since we expect any increase in component prices for compression equipment or packaging costs will be passed on to us, a significant increase in their pricing could have a negative impact on our results of operations.

The contract treating business within our Contract Services segment depends on particular suppliers and is vulnerable to parts and equipment shortages and price increases, which could have a negative impact on our results of operations.

Our contract treating business' ability to manufacture new equipment used to provide treating services, and to obtain replacement components, depends on particular suppliers and is sensitive to equipment shortages and price increases. Spitzer Industries, the principal manufacturer and packager of amine plants, determines the cost of our contract treating equipment based primarily on the price and availability of commodities (i.e. steel), components and labor. If a significant increase in the cost of manufacturing were to occur, our contract treating business could see a reduced rate of return on its capital investments absent offsetting increases in revenue rates.

In accordance with industry practice, we do not obtain independent evaluations of natural gas reserves dedicated to our gathering systems. Accordingly, volumes of natural gas gathered on our gathering systems in the future could be less than we anticipate, which could adversely affect our business and operating results.

We do not obtain independent evaluations of natural gas reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations.

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Accordingly, we do not have estimates of total reserves dedicated to our systems or the anticipated lives of such reserves. If the total reserves or estimated lives of the reserves connected to our gathering systems are less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas gathered on our gathering systems in the future could be less than we anticipate. A decline in the volumes of natural gas gathered on our gathering systems could have an adverse effect on our business, results of operations and financial condition.

In our gathering and processing operations, we purchase raw natural gas containing significant quantities of NGLs, process the raw natural gas and sell the processed gas and NGLs. If we are unsuccessful in balancing the purchase of raw natural gas with its component NGLs and our sales of pipeline quality gas and NGLs, our exposure to commodity price risks will increase.

We purchase from producers and other customers a substantial amount of the natural gas that flows through our natural gas gathering and processing systems and our RIGS transportation pipeline for resale to third parties, including natural gas marketers and utilities. We may not be successful in balancing our purchases and sales. In addition, a producer could fail to deliver promised volumes or could deliver volumes in excess of contracted volumes, a purchaser could purchase less than contracted volumes, or the natural gas price differential between the regions in which we operate could vary unexpectedly. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating results.

Our results of operations and cash flow may be adversely affected by risks associated with our hedging activities.

In performing our functions in our gathering and processing segment, we are a seller of natural gas and NGLs and are exposed to commodity price risk associated with movements in commodity prices. As a result of the volatility of commodity prices and interest rates, we have executed swap contracts or put options settled against ethane, propane, normal butane, natural gas, natural gasoline and west Texas intermediate crude market prices. We continually monitor our hedging and contract portfolio and expect to adjust our hedge position as conditions warrant. For more information about our risk management activities, read “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.” Even though our management monitors our hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including any circumstance in which a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect, or our hedging policies and procedures are not followed or do not work as planned.

The adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress has adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), a comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The legislation was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. While certain regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

The Dodd-Frank Act expanded the types of entities that are required to register with the CFTC and the SEC as a result of their activities in the derivatives markets or otherwise become specifically qualified to enter into derivatives contracts. We will be required to assess our activities in the derivatives markets, and to monitor such activities on an ongoing basis, to ascertain and to identify any potential change in our regulatory status.

Reporting and recordkeeping requirements also could significantly increase operating costs and expose us to penalties for noncompliance. Certain CFTC recordkeeping requirements became effective on October 14, 2010, and additional recordkeeping requirements will be phased in through April 2013. Beginning on December 31, 2012, certain CFTC reporting rules became effective, and additional reporting requirements will be phased in through April 2013. These additional recordkeeping and reporting requirements may require additional compliance resources. Added public transparency as a result of the reporting rules may also have a negative effect on market liquidity which could also negatively impact commodity prices and our ability to hedge.

The CFTC has also issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The CFTC's position limits rules were to become effective on October 12, 2012,but a United States District Court vacated and remanded the position limits rules to the CFTC. The CFTC has appealed that ruling and it is uncertain at this time whether, when, and to what extent the CFTC's position limits rules will become effective.

The new regulations may also require us to comply with certain margin requirements for our over-the counter derivative contracts with certain CFTC- or SEC-registered entities that could require us to enter into credit support documentation and/or post significant amounts of cash collateral, which could adversely affect our liquidity and ability to use derivatives to hedge our commercial price risk; however, the proposed margin rules are not yet final and therefore the application of those provisions to us is uncertain at

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this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation also requires that certain derivative instruments be centrally cleared and executed through an exchange or other approved trading platform. Mandatory exchange trading and clearing requirements could result in increased costs in the form of additional margin requirements imposed by clearing organizations. On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which is March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. Although there may be an exception to the mandatory exchange trading and clearing requirement that applies to our trading activities, we must obtain approval from the board of directors of our General Partner and make certain filings in order to rely on this exception. In addition, mandatory clearing requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

Rules promulgated under the Dodd-Frank Act further defined forwards as well as instances where forwards may become swaps. Because the CFTC rules, interpretations, no-action letters, and case law are still developing, it is possible that some arrangements that previously qualified as forwards or energy service contracts may fall in the regulatory category of swaps or options. In addition, the CFTC's rules applicable to trade options may further impose burdens on our ability to conduct our traditional hedging operations and could become subject to CFTC investigations in the future.

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, if we fail to comply with applicable laws, rules or regulations, we may be subject to fines, cease-and-desist orders, civil and criminal penalties or other sanctions.

To the extent that we intend to grow internally through construction of new, or modification of existing, facilities, we may not be able to manage that growth effectively, which could decrease our cash flow and adversely affect our results of operations.

A principal focus of our strategy is to continue to grow by expanding our business both internally and through acquisitions. Our ability to grow internally will depend on a number of factors, some of which will be beyond our control. We may not be able to finance the construction or modifications on satisfactory terms. In general, the construction of additions or modifications to our existing systems, and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control. Any project that we undertake may not be completed on schedule, at budgeted cost or at all. Construction may occur over an extended period, and we are not likely to receive a material increase in revenues related to such project until it is completed. Moreover, our revenues may not increase immediately upon the completion of construction because the anticipated growth in gas production that the project was intended to capture does not materialize, our estimates of the growth in production prove inaccurate or for other reasons. For example, producers in the area may decrease their activity levels in the area near HPC due to the declines in the price for natural gas. To the extent producers in the area are unable to execute their expected drilling programs, the return on our investment from this project may not be as attractive as we anticipate. For any of these reasons, newly constructed or modified midstream facilities may not generate our expected investment return and that, in turn, could adversely affect our cash flows and results of operations. In addition, our ability to undertake to grow in this fashion will depend on our ability to hire, train, and retain qualified personnel to manage and operate these facilities when completed.

We may have difficulty financing our planned capital expenditures, including in our joint ventures, which could adversely affect our results and growth.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including borrowings under our credit facility and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. If we are not able to obtain adequate financing from the capital markets, our ability to grow and our results of operations could be adversely impacted. To access amounts under our credit facility for joint venture capital expenditures or additional investments, we may need to amend to our credit facility, and we cannot assure you that we can obtain any such amendment.

Our leverage may limit our ability to borrow additional funds, make distributions, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners' capital. Our debt to capital ratio, calculated as total debt divided by the sum of total debt and partners' capital, as of December 31, 2012 was 41%. We will be prohibited from making cash distributions during

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an event of default under any of our indebtedness, and, in the case of the indenture under which our senior notes were issued, the failure to maintain a prescribed ratio of consolidated cash flows (as defined in the indenture) to interest expense. Various limitations in our credit facility, as well as the indentures for our senior notes, may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or otherwise realize fully the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

Increases in interest rates could adversely impact our common unit price and our ability to issue additional equity, in order to make acquisitions, to reduce debt, or for other purposes.

The interest rates on our senior notes are fixed and the loans outstanding under our credit facility bear interest at a floating rate. Interest rates on future credit facilities and debt offerings could be significantly higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, the market price for our units will be affected by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse effect on our unit price and our ability to issue additional equity in order to make acquisitions, to reduce debt or for other purposes.

Because we distribute all of our available cash to our unitholders, our future growth may be limited.

Since we will distribute all of our available cash to our unitholders, subject to the limitations on restricted payments contained in the indentures governing our senior notes and our credit facility, we will depend on financing provided by commercial banks and other lenders and the issuance of debt and equity securities to finance any significant internal organic growth or acquisitions. If we are unable to obtain adequate financing from these sources, our ability to grow will be limited.

Certain of our assets may become subject to regulation.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. Lone Star’s West Texas Pipeline transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGLs transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. Such services must be provided in a manner that is just, reasonable and non-discriminatory. We believe that this NGLs system does not provide interstate service and thus, is not subject to FERC jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. However, we cannot assure you that the jurisdictional status of this NGLs pipeline system will remain unchanged. If the system should be found to provide FERC-jurisdictional services, the FERC’s rate-making methodologies may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

Our interstate gas transportation operations, including Section 311 service performed by our intrastate pipelines, our sales of gas in interstate commerce, and our shipment of gas on interstate pipelines are subject to FERC regulation; failure to comply with applicable regulation, future changes in regulations or policies, or the establishment of more onerous terms and conditions applicable to natural gas transportation service could adversely affect our business.

FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines, such as the pipelines owned by Gulf States and MEP, both of which hold FERC-approved tariffs setting forth cost- based rates, terms and conditions for services to shippers wishing to take interstate transportation service. Under the NGA, rates charged for, and the terms and conditions of service of, interstate natural gas transmission must be just and reasonable, and amounts collected in excess of just and reasonable rates may be subject to refund with interest. In addition, FERC regulates the rates, terms and conditions of service with respect to Section 311 transportation service provided by HPC (through RIGS). FERC has authority to alter its rules, regulations and policies governing service provided by interstate pipelines and intrastate pipelines providing Section 311 services. We cannot give any assurance regarding the likely future regulations under which Gulf States, MEP or HPC will operate their interstate transportation services or the effect such regulation could have on our businesses or results of operations. In addition, FERC also has broad authority to require compliance with its rules and regulations and to prohibit and penalize manipulative behavior that affects markets. Since our gathering and processing businesses sell natural gas in interstate commerce and ship gas on interstate pipelines, these activities are subject to FERC oversight. Any failure on our part to comply with applicable FERC-administered

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statutes, rules, regulations and orders could result in the imposition of significant administrative, civil and/or criminal penalties or both, as well as increased operational requirements or prohibitions.

As limited partnership entities, neither we nor our regulated natural gas pipelines may be able to include a full tax allowance in calculating our costs-of-service for rate-making purposes.

Under current policy applied under the NGA and Section 311, FERC permits regulated natural gas pipelines to include, in the cost-of-service used as the basis for calculating the pipeline's regulated rates, a tax allowance reflecting the actual or potential income tax liability on pipeline income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis, and the pipeline is required to demonstrate that such potential income tax liability exists. Although FERC's policy is generally favorable for pipelines that are organized as, or owned by, tax-pass-through entities, application of the policy in individual rate cases still entails rate risk due to the case-by-case review requirement. The specific terms and application of that policy remain subject to future refinement or change by FERC and the courts. Moreover, we cannot guarantee that this policy will not be altered in the future.

There are uncertainties in the calculation of the return on equity that FERC will authorize a natural gas pipeline to include in its cost-of-service.

An important part of the determination of rates by FERC is the establishment of an authorized return on equity. FERC currently calculates a range of potential returns, based on a discounted cash flow analysis of companies included in a proxy group, and then determines where a pipeline's risks require it to be placed within this range. FERC policy also currently allows the inclusion of master limited partnerships, or MLPs, in proxy groups used to calculate the appropriate returns on equity under FERC's discounted cash flow analysis, but FERC limits recognition of certain MLP earnings and allows case-by-case determination by FERC of the appropriateness of any MLP, or indeed any stock corporation, proposed as a member of the pipeline's proxy group.

A change in the level of regulation or the jurisdictional characterization of some of our assets or business activities by federal, state or local regulatory agencies could affect our operations and revenues.

Our natural gas gathering, processing and intrastate transportation operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. With the passage of the Energy Policy Act of 2005 (EPACT 2005), FERC has expanded its oversight of natural gas purchasers, natural gas sellers, gatherers, intrastate pipelines and shippers on FERC regulated pipelines by imposing new market monitoring and market transparency rules and rules prohibiting manipulative behavior. In addition, EPACT 2005 substantially increased FERC's penalty authority. In recent years, FERC has adopted rules requiring increased reporting by purchasers and sellers of natural gas and increased transactional reporting requirements for intrastate pipelines. In 2010, FERC also sought formal comments on the applicability of buy-sell prohibitions and capacity release requirements on intrastate pipelines that provide interstate service under NGPA Section 311. We cannot predict the outcome of this proceeding or how FERC will approach future matters such as pipeline rates and rules and policies that may affect purchases or sales of natural gas or rights of access to natural gas transportation capacity.

In addition, the distinction between FERC-regulated interstate transmission service, on one hand, and intrastate transmission or federally unregulated gathering services, on the other hand, is the subject of regular litigation at FERC and in the courts and of policy discussions at FERC. In such circumstances, the classification and regulation of some of our gathering or our intrastate transportation pipelines may be subject to change based on future determinations by FERC, the courts, or Congress. Such a change could result in increased regulation by FERC, which could adversely affect our business.

Other state and local regulations also affect our business. Our gathering pipelines are subject to ratable take and common purchaser statutes in states in which we operate. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. Many states in which we operate have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our intrastate NGL, crude oil, and condensate pipelines are subject to state common carrier regulations, which require just and reasonable rates, non-discriminatory service, and the filing of tariffs. Our common carrier pipeline tariffs contemplate a higher level of service for “anchor shippers”, and if these or any other provisions in our common carrier pipeline tariffs are found to be inconsistent with non-discrimination requirements, then we may be required to modify the rates and/or terms of service in our tariffs and may not be able to provide the level of service contemplated in agreements with “anchor shippers”.

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Any new laws, rules, regulations or orders could result in additional compliance costs and/or requirements, which could adversely affect our business. If we fail to comply with any new or existing laws, rules, regulations or orders, we could be subject to administrative, civil and/or criminal penalties, or both, as well as increased operational requirements or prohibitions.

We may be unable to integrate successfully the operations of future acquisitions with our operations, and we may not realize all the anticipated benefits of our past and any future acquisitions.

Integration of acquisitions with our business and operations is a complex, time consuming, and costly process. Failure to integrate acquisitions successfully with our business and operations in a timely manner may have a material adverse effect on our business, financial condition, and results of operations. We cannot assure you that we will achieve the desired profitability from past or future acquisitions. In addition, failure to assimilate future acquisitions successfully could adversely affect our financial condition and results of operations. Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the risk that natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant producers or markets or key employees from the acquired business;
- the availability of local, intrastate and interstate transportation system;
- the diversion of management’s attention from other business concerns;
- the failure to realize expected profitability, growth or synergies and cost savings;
- properly assessing and managing environmental compliance;
- coordinating geographically disparate organizations, systems, and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

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

We compete with similar enterprises in each of our areas of operations. Some of our competitors are large oil, natural gas, gathering and processing and natural gas and NGL pipeline companies that have greater financial resources and access to supplies of natural gas and NGLs than we do. In addition, our customers who are significant producers or consumers of NGLs may develop their own processing facilities in lieu of using ours. Similarly, competitors may establish new connections with pipeline systems that would create additional competition for services that we provide to our customers. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors.

The natural gas contract compression business is highly competitive, and there are low barriers to entry for individual projects. In addition, some of our competitors are large national and multinational companies that have greater financial and other resources than we do. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flows could be adversely affected by the activities of our competitors and our customers. If our competitors substantially increase the resources they devote to the development and marketing of competitive services or substantially decrease the prices at which they offer their services, we may be unable to compete effectively. Some of these competitors may expand or construct newer or more powerful compressor fleets that would create additional competition for us. In addition, our customers that are significant producers of natural gas and crude oil may purchase and operate their own compressor fleets in lieu of using our natural gas contract compression services. All of these competitive pressures could have a material adverse effect on our business, results of operations, and financial condition.

Any reduction in the capacity of, or the allocations to, our shippers in interconnecting, third-party pipelines could cause a reduction of volumes transported in our pipelines, which would adversely affect our revenues and cash flow. Users of our pipelines are dependent upon connections to and from third-party pipelines to receive and deliver natural gas and NGLs. Any reduction in the capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures,

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or other causes could result in reduced volumes being transported in our pipelines. Similarly, if additional shippers begin transporting volumes of natural gas and NGLs over interconnecting pipelines, the allocations to existing shippers in these pipelines could be reduced, which could also reduce volumes transported in our pipelines. Any reduction in volumes transported in our pipelines would adversely affect our revenues and cash flow.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders. Many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve based credit facilities (resulting from a decline in commodity prices) and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us.

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

Our operations are subject to the many hazards inherent in the gathering, processing and transportation of natural gas and the transportation, fractionation and storage of NGLs, including:

- damage to our gathering and processing facilities, pipelines, fractionation and storage related equipment and surrounding properties caused by tornadoes, floods, hurricanes, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipments;
- leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of pipelines, measurement equipment or facilities at receipt or delivery points;
- fires and explosions;
- weather related hazards, such as hurricanes and extensive rains which could delay the construction of assets and extreme cold which could cause freezing of pipelines, limiting throughput.; and
- other hazards, including those associated with high-sulfur content, or sour gas, such as an accidental discharge of hydrogen sulfide gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not insured against all environmental events that might occur. If a significant accident or event occurs that is not insured or fully insured, it could adversely affect our operations and financial condition.

Failure of the natural gas that we ship on our pipelines to meet the specifications of interconnecting interstate pipelines could result in curtailments by the interstate pipelines.

The markets to which the shippers on our pipelines ship natural gas include interstate pipelines. These interstate pipelines establish specifications for the natural gas that they are willing to accept, which include requirements such as hydrocarbon dew point, temperature and foreign content including water, sulfur, carbon dioxide and hydrogen sulfide. These specifications vary by interstate pipeline. If the total mix of natural gas shipped by the shippers on our pipeline fails to meet the specifications of a particular interstate pipeline, it may refuse to accept all or a part of the natural gas scheduled for delivery to it. In those circumstances, we may be required to find alternative markets for that gas or to shut-in the producers of the non-conforming gas, potentially reducing our throughput volumes or revenues.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any related pipeline repair, or preventative or remedial measures, as well as any future legislative and regulatory initiatives related to pipeline safety.

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines and certain gathering lines located where a leak or rupture could do the most harm in "high consequence areas." The regulations require operators to:

- perform ongoing assessments of pipeline integrity;

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- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. We currently estimate that we will incur costs of $0.5 million in 2013 to implement pipeline integrity management program testing along certain segments of our pipeline, as required by existing DOT regulations. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial.

The DOT is continually proposing new pipeline safety rules and issuing pipeline safety advisories that impact our businesses. Additionally, Congress has been engaged in developing more stringent safety laws.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, became effective. The new law requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The law requires numerous studies and/or the development of rules over the next two years covering the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related rules. The DOT has already sought comments on potential rules that address many areas of the newly adopted legislation. Any regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations, increased costs and higher penalties for the violation of those regulations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of increased costs or the inability to retain necessary land use.

We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies. Many of these rights-of-way are perpetual in duration; others have terms ranging from five to ten years. Many are subject to rights of reversion in the case of non-utilization for periods ranging from one to three years. In addition, some of our processing facilities are located on leased premises. Our loss of these rights, through our inability to renew right-of-way contracts or leases or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to connect new natural gas or NGL supplies to our existing pipelines or to capitalize on other attractive expansion opportunities. If the cost of obtaining new rights-of-way increases, then our cash flows and growth opportunities could be adversely affected. Additionally, certain of our pipelines are gas utilities or common carrier pipelines with the statutory right of eminent domain. A recent Texas Supreme Court decision could severely limit our ability to use eminent domain to acquire right-of-way for common carrier expansion and growth projects, and potentially gas utility projects. Any such limitations could adversely affect our growth opportunities and cash flows.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or releases of hazardous materials into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and other criminal sanctions, third party claims for personal injury or property damage, investments to retrofit or upgrade our facilities and programs, or curtailment of operations. Certain environmental statutes, including CERCLA and comparable state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to the necessity of handling natural gas and NGLs, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance. We cannot be certain that identification of presently unidentified conditions, more vigorous enforcement by regulatory agencies, enactment of

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more stringent laws and regulations, or other unanticipated events will not arise in the future and give rise to material environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

We operate an injection well to dispose of hydrogen sulfide and carbon dioxide in McMullen County, Texas. A local producer has filed a complaint before the Railroad Commission of Texas and is seeking modification or termination of our authority to operate the well. The Railroad Commission of Texas is convening a hearing on the matter. We cannot predict the outcome of the proceeding, but any suspension or termination of the permit would adversely affect our business and results of operations.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the natural gas and other hydrocarbon products that we transport, process, or otherwise handle in connection with our transportation and midstream services.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth’s atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA adopted two sets of regulations addressing greenhouse gas emissions under the Clean Air Act. The first limits emissions of greenhouse gases from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle greenhouse gas emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. In June 2010, the EPA published its final rule to address the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. This rule “tailors” these permitting programs to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to “best available control technology” standards for greenhouse gases, which are currently being developed on a case-by-case basis. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce or sequester emissions of greenhouse gases associated with our operations and also could adversely affect demand for the natural gas and other hydrocarbon products that we transport, process, or otherwise handle in connection with our services.

In addition, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. In November 2010, the EPA revised its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Under these new rules, reporting of greenhouse gas emissions from such facilities, including many of our facilities, is required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

Various pieces of legislation to reduce emissions of, or to create cap and trade programs for, greenhouse gases have been proposed by the U.S. Congress over the past several years, but no proposal has yet passed. More than one-third of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our own operations, and it could also adversely affect demand for our transportation, storage and midstream services.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our NGLs and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term “global warming” as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

We may not have the ability to raise funds necessary to finance any change of control offer required under our senior notes and our Series A Preferred Units or to repay our credit facility upon a change of control.

If a change of control (as defined in the indentures governing our senior notes) occurs, we will be required to offer to purchase our outstanding senior notes at 101% of their principal amount plus accrued and unpaid interest. If a purchase offer obligation arises under these indentures, a change of control could also have occurred under our credit facility, which could result in the acceleration of the indebtedness outstanding thereunder. Further, if a change of control (as defined in our partnership agreement) occurs, we will be required, under certain circumstances, to offer to purchase the Series A Preferred Units at 120% of their liquidation

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value (as defined in our partnership agreement) for the first five years after their issuance and thereafter at 101% of their liquidation value. Any of our future debt agreements may contain similar restrictions and provisions. If a purchase offer were required under the indentures for our debt (or repayment under our credit facility), we may not have sufficient funds to pay the purchase price of all debt that we are required to purchase or repay.

Our ability to manage and grow our business effectively may be adversely affected if our General Partner loses key management or operational personnel.

We depend on the continuing efforts of our executive officers. The departure of any of our executive officers could have a significant negative effect on our business, operating results, financial condition, and on our ability to compete effectively in the marketplace. Additionally, the General Partner's employees operate some of our business activities. Our General Partner's ability to hire, train, and retain qualified personnel will continue to be important and will become more challenging as we grow and if energy industry market conditions remain positive.

When general industry conditions are good, the competition for experienced operational and field technicians increases as other energy and manufacturing companies' needs for the same personnel increases. Our ability to grow and perhaps even to continue our current level of service to our current customers will be adversely impacted if our General Partner or its affiliates that provide these personnel are unable to successfully hire, train and retain these important personnel.

Terrorist attacks, the threat of terrorist attacks, hostilities in the Middle East, or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the magnitude of the threat of future terrorist attacks on the energy transportation industry in general and on us in particular are not known at this time. Uncertainty surrounding hostilities in the Middle East or other sustained military campaigns may affect us in unpredictable ways, including disruptions of natural gas supplies and markets for natural gas and NGLs and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and maintaining credit ratings is under the control of independent third parties.

A downgrade of our credit rating might increase our cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our ability to access capital markets could also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions;
- declining market prices for natural gas, NGLs and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

ETE may sell units in the public or private markets, and the sale could have an adverse impact on the price of our common units.

ETE owns 26,266,791 of our common units. We have agreed to provide to ETE the right to register for resale its common units. The sale of these common units in the public or private markets could have an adverse impact on the price of our common units or on the trading market for them.

An impairment of goodwill and intangible assets could reduce our earnings.

At December 31, 2012, our consolidated balance sheet reflected $790 million of goodwill and $712 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur that indicate goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets are impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' capital and balance sheet leverage as measured by debt to total capitalization.

If we do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our results of operations and our ability to grow and to increase distributions to unitholders will depend in part on our ability to make acquisitions that are accretive to our distributable cash flow per unit.

We may be unable to make accretive acquisitions for any of the following reasons, among others:

- because we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- because we are unable to raise financing for such acquisitions on economically acceptable terms; or
- because we are outbid by competitors, some of which are substantially larger than us and have greater financial resources and lower costs of capital then we do.

If we consummate future acquisitions, our capitalization and results of operations may change significantly. As we determine the application of our funds and other resources, unitholders will not have an opportunity to evaluate the economics, financial and other relevant information that we will consider.

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

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate production. While the underground injection of fluids is regulated by the U.S. EPA under the Safe Drinking Water Act ("SWDA"), fracturing is excluded from regulation unless the injection fluid is diesel fuel. Congress has recently considered legislation that would repeal the exclusion, allowing EPA to more generally regulate fracturing, and requiring disclosure of chemicals used in the fracturing process. If enacted, such legislation could require fracturing to meet permitting and financial responsibility, siting and technical specifications relating to well construction, plugging and abandonment. EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production. In November 2011, EPA indicated it may initiate rulemaking under the Toxic Substances Control Act to obtain data regarding the composition of hydraulic fracturing fluids. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations, increase our and our customers' costs of compliance, and adversely affect the hydraulic fracturing services that we render for our E&P customers. In addition, the U.S. EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Results of the study are expected between later in 2012 and 2014. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

On April 17, 2012 EPA approved final rules establishing new air emission standards for oil and natural gas production and natural gas processing operations. This rulemaking addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. For new or reworked hydraulically-fractured wells, the final rule requires controlling emissions through flaring until 2015, when the rule requires the use of reduced emission (or "green") completions, meaning equipment must be installed to separate gas and liquid hydrocarbons at the well head, enabling gas capture. The rule also establishes specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks gas processing plants and certain other equipment. These rules may require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. Compliance with these rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Additional federal or state legislation or regulation of hydraulic fracturing or related activities could result in operational delays, increased operating costs, and additional regulatory burdens on exploration and production operators, as well as aspects of our business. This could reduce production of natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas and NGLs that we gather, process and transport.

Some portions of our current gathering infrastructure and other assets have been in use for many decades, which may adversely affect our business.

Some portions of our assets, including some of our gathering infrastructure, have been in use for many decades. The current age and condition of our assets could result in a material adverse impact on our business, financial condition and results of operations if the costs of maintaining our facilities exceed current expectations.

RISKS RELATED TO OUR STRUCTURE

Our General Partner is owned by ETE, which also owns Southern Union and the general partner of ETP and SXL. This may result in conflicts of interest.

ETE owns our General Partner and as a result controls us. ETE owns the general partner of ETP, a publicly traded partnership with which we compete in the natural gas gathering, processing and transportation business. ETE owns Southern Union who, through SUGC, competes with us in the natural gas gathering, processing and transportation business. ETE also owns the general partner of SXL, who is also in the NGL Services business.The directors and officers of our General Partner and its affiliates have fiduciary duties to manage our General Partner in a manner that is beneficial to ETE, its sole owner. At the same time, our General Partner has fiduciary duties to manage us in a manner that is beneficial to our unitholders. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ETE, ETP, Southern Union, SXL, or their owners or affiliates over the interest of our unitholders.

Such conflicts may arise from, among others, the following:

- Decisions by our General Partner regarding the amount and timing of our cash expenditures, borrowings and issuances of additional limited partnership units or other securities can affect the amount of incentive compensation payments on our IDRs we make to the parent company of our General Partner;
- ETE and ETP and their affiliates may engage in substantial competition with us;
- Neither our partnership agreement nor any other agreement requires ETE or its affiliates, including ETP, Southern Union and SXL, to pursue a business strategy that favors us. The directors and officers of the general partners of ETE and ETP, as well as the directors and officers of Southern Union and SXL, have a fiduciary duty to make decisions in the best interest of their members, limited partners and unitholders, which may be contrary to our best interests;
- Our General Partner is allowed to take into account the interests of other parties, such as ETE, ETP, Southern Union and SXL and their affiliates, which has the effect of limiting its fiduciary duties to our unitholders;
- Some of the directors and officers of ETE who provide advice to us also may devote significant time to the business of ETE, ETP, Southern Union and SXL and their affiliates and will be compensated by them for their services;
- Our partnership agreement limits the liability and reduces the fiduciary duties of our General Partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty;
- Our General Partner determines the amount and timing of asset purchases and sales and other acquisitions, operating expenditures, capital expenditures, borrowings, repayments of debt, issuances of equity and debt securities and cash reserves, each of which can affect the amount of cash available for distribution to our unitholders;
- Our General Partner determines which costs, including allocated overhead costs and costs under the services agreement we have with Service Co. and our operating agreement with ETP, incurred by it and its affiliates are reimbursable by us; and
- Our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements, such as the services agreement we have with an affiliate of ETE and operating agreement with ETP, with any of these entities on our behalf.

Specifically, certain conflicts may arise as a result of our pursuing acquisitions or development opportunities that may also be advantageous to ETP. If we are limited in our ability to pursue such opportunities, we may not realize any or all of the commercial value of such opportunities. In addition, if ETP is allowed access to our information concerning any such opportunity and ETP uses this information to pursue the opportunity to our detriment, we may not realize any of the commercial value of this opportunity. In either of these situations, our business, results of operations and the amount of our distributions to our unitholders may be adversely affected. Although we, ETE and ETP have adopted a policy to address these conflicts and to limit the commercially

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sensitive information that we furnish to ETE, ETP and their affiliates, we cannot assure unitholders that such conflicts will not occur.

Our reimbursement of our General Partner's expenses will reduce our cash available for distribution to common unitholders.

Prior to making any distribution on the common units, we will reimburse our General Partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by our General Partner and its affiliates in managing and operating us, including costs for rendering corporate staff and support services to us. The reimbursement of expenses incurred by our General Partner and its affiliates could adversely affect our ability to pay cash distributions to our unitholders.

Our partnership agreement limits our General Partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our General Partner might otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our General Partner to make a number of decisions in its individual capacity, as opposed to its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership;
- provides that our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of our General Partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us, as determined by our General Partner in good faith, and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

Any unitholder is bound by the provisions in the partnership agreement, including those discussed above.

Unitholders have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders do not elect our General Partner or its Board of Directors and have no right to elect our General Partner or its Board of Directors on an annual or other continuing basis. The Board of Directors of our General Partner is chosen by the members of our General Partner. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which our common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if unitholders are dissatisfied, they cannot remove our General Partner without its consent.

Our unitholders may be unable to remove the General Partner without its consent because the General Partner and its affiliates own a substantial number of common units. A vote of the holders of at least 66.67% of all outstanding units voting together as a single class is required to remove the General Partner. As of February 22, 2013, affiliates of our General Partner owned 15.4% of the total of our common units.

Our partnership agreement restricts the voting rights of those unitholders owning 20% or more of our common units or Series A Preferred Units.

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

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agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of our management.

Control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its general partner interest in us to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the partners of our General Partner from transferring their ownership in our General Partner to a third party. The new partners of our General Partner would then be in a position to replace the Board of Directors and officers of our General Partner with their own choices and to control the decisions taken by the Board of Directors and officers.

We may issue an unlimited number of additional units without unitholders' approval, which would dilute the ownership interest of existing unitholders.

Our General Partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional common units or other equity securities. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

If at any time our General Partner and its affiliates own more than 80% of the common units, our General Partner will have the right, but not the obligation (which it may assign to any of its affiliates or to us) to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. As of February 22, 2013, affiliates of our General Partner owned 15.4% of the total number of outstanding common units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our General Partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our General Partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our General Partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets. Additionally, we are not able to control the amounts of cash that HPC, MEP, Lone Star or Ranch JV may distribute to us.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to make required payments on our debt obligations and distributions on our common units depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, our revolving credit facility and applicable state partnership and limited liability company laws and other laws and regulations. Pursuant to our revolving credit facility, we may be required to establish cash reserves for the future repayment of outstanding letters of credit under our revolving credit facility. If we are unable to obtain the funds necessary to pay the principal amount at maturity of our debt obligations, to repurchase our debt obligations upon the occurrence of a change of control or make distributions on our common units, we may be required to adopt one or more alternatives, such as a refinancing of our debt obligations or borrowing funds to make distributions on our common units. We cannot assure unitholders that we would be able to borrow funds to make distributions on our common units.

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Additionally, the ability of our joint ventures to make distributions to us may be restricted by, among other things, the terms of each such entity's partnership or limited liability company agreement, as applicable, and any debt instruments entered into by such entity as well as applicable state partnership or limited liability company laws, as applicable, and other laws and regulations. We do not control the amounts of cash that our joint ventures may distribute to us.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner, and of ETE as the indirect owner of our General Partner, may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our General Partner and ETE over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from us to service their indebtedness.

ETE has significant indebtedness outstanding and is dependent principally on the cash distributions from its general and limited partner equity interests in us and ETP to service such indebtedness. Any distributions by us to ETE will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our General Partner from the entities that control our General Partner (ETE and its general partner), our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of such entities were viewed as substantially lower or riskier than ours.

TAX RISKS

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states or local entities. If the IRS treats us as a corporation or we become subject to a material amount of entity-level taxation for state or local tax purposes, it would substantially reduce the amount of cash available for payment for distributions on our common units.

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation has recently been considered that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have applied to us as proposed, it could be reintroduced in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay a Texas margin tax. Imposition of such a tax on us by Texas, and, if applicable, by any other state, will reduce our cash available for distribution to our common unitholders.

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

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the cost of any IRS contest will reduce our cash available for distribution to you.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our cash available for distribution.

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Unitholders may be required to pay taxes on income from us even if you do not receive any cash distributions from us.
Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.
Tax gain or loss on disposition of common units could be more or less than expected.
If a unitholder sells his common units, he will recognize a gain or loss equal to the difference between the amount realized and his tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income he was allocated for a common unit, which decreased his tax basis in that common unit, will, in effect, become taxable income to him if the common unit is sold at a price greater than his tax basis in that common unit, even if the price is less than his original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells his common units, he may incur a tax liability in excess of the amount of cash he receives from the sale.
Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.
Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If a unitholder is a tax-exempt entity or a non-U.S. person, he should consult his tax advisor before investing in our common units.
We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.
Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax deductions available to a unitholder. It also could affect the timing of these tax deductions or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.
We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.
We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. However, recently proposed Treasury Regulations provide a safe harbor for publicly traded partnerships pursuant to which a similar monthly convention is allowed. Existing publicly traded partnerships are entitled to rely on these proposed Treasury Regulations; however they are not binding on the IRS and are subject to change until final Treasury Regulations are issued. Accordingly, if the IRS were to challenge our method of allocating income, gain, loss and deduction between transferors and transferees, or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.
A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders

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desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation and allocation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

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

In addition, for purposes of determining the amount of the unrealized gain or loss to be allocated to the capital accounts of our unitholders and our General Partner, we will reduce the fair market value of our property (to the extent of any unrealized income or gain in our property that has not previously been reflected in the capital accounts) to reflect the incremental share of such fair market value that would be attributable to the holders of our outstanding convertible redeemable preferred units if all of such convertible redeemable preferred units were converted into common units as of such date. Consequently, a holder of common units may be allocated less unrealized gain in connection with an adjustment of the capital accounts than such holder would have been allocated if there were no outstanding convertible redeemable preferred units. Following the conversion of our convertible redeemable preferred units into common units, items of gross income and gain (or gross loss and deduction) will be specially allocated to the holders of such common units to reflect differences between the capital accounts maintained with respect to such convertible redeemable preferred units and the capital accounts maintained with respect to common units. This method of maintaining capital accounts and allocating income, gain, loss and deduction with respect to the convertible redeemable preferred units is intended to comply with proposed Treasury Regulations. However, these proposed Treasury Regulations are not legally binding and are subject to change until final Treasury Regulations are issued. Accordingly, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been reached, multiple sales of the same unit will be counted only once. Although a termination likely will cause our unitholders to realize an increased amount of taxable income as a percentage of the cash distributed to them, we anticipate that the ratio of taxable income to distributions for future years will return to levels commensurate with our prior tax periods. However, any future termination of our partnership could have similar consequences. Additionally, in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. The position that there was a partnership termination does not affect our classification as a partnership for federal income tax purposes; however, we are treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to prevail that a termination occurred. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminates requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

You may be subject to state and local taxes and tax return filing requirements.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and do business in Texas, Oklahoma, Kansas, Louisiana, West Virginia, Arkansas,

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Colorado, Alabama, California, Mississippi, New Mexico, Utah and Pennsylvania. Each of these states, other than Texas, currently imposes a personal income tax as well as an income tax on corporations and other entities. Texas imposes a margin tax on corporations, limited partnerships, limited liability partnerships and limited liability companies. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns required as a result of being a unitholder.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Substantially all of our pipelines (including those of HPC, MEP, Lone Star and Ranch JV), which are located in Texas, Louisiana, Oklahoma, Mississippi, Alabama, and Kansas, are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, properties on which our pipelines were built were purchased in fee. These pipelines are used in our gathering and processing segment, natural gas transportation segment and NGL Services segment.

We believe that we have satisfactory title to all our assets. Record title to some of our assets may continue to be held by prior owners until we have made the appropriate filings in the jurisdictions in which such assets are located. Obligations under our credit facility are secured by substantially all of our assets and are guaranteed by the Partnership. Title to our assets may also be subject to other encumbrances. We believe that none of such encumbrances should materially detract from the value of our properties or our interest in those properties or should materially interfere with our use of them in the operation of our business.

Our executive offices occupy two entire floors in an office building at 2001 Bryan Street, Suite 3700, Dallas, Texas, 75201, under a lease that expires on October 31, 2019. We also maintain regional offices located on leased premises in Louisiana and Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

For additional information regarding our properties, read “Item 1. Business.”

Item 3. Legal Proceedings

We are subject to a variety of risks and disputes normally incident to our business. As a result, we may, at any given time, be a defendant in various legal or governmental proceedings and litigation arising in the ordinary course of business. Neither the Partnership nor any of its subsidiaries is, however, currently a party to any material pending or, to our knowledge, threatened material legal or governmental proceedings, including proceedings under any of the various environmental protection statutes to which they are subject.

We maintain insurance policies with insurers in amounts and with coverages and deductibles that we, with the advice of our insurance advisers and brokers, believe are reasonable and prudent. We cannot, however, assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

For a description of legal proceedings, see Note 12 in the Notes to our Consolidated Financial Statements.

Item 4. Mine Safety Disclosures

Not applicable.

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Part II

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

Market Price of and Distributions on the Common Units and Related Unitholder Matters

Our common units were first offered and sold to the public on February 3, 2006. On August 9, 2011, we transferred the listing of our common units from the NASDAQ to the NYSE. Our common units are currently listed on the NYSE under the symbol "RGP." As of February 22, 2013, the number of holders of record of common units was 38, with 144,219,733 units held in street name.

The following table sets forth, for the periods indicated, the high and low quarterly sales prices per common unit, as reported on the NYSE and on the NASDAQ prior to August 9, 2011, and the cash distributions declared per common unit, excluding the Series A Preferred Units which began receiving fixed quarterly cash distributions of $0.445 beginning with the quarter ending March 31, 2010:

Period	Price Ranges High	Price Ranges Low	Cash Distributions (per common unit)
2012			
Fourth Quarter	$24.28	$20.87	$0.460
Third Quarter	24.30	22.10	0.460
Second Quarter	25.18	21.06	0.460
First Quarter	27.00	23.93	0.460
2011			
Fourth Quarter	24.88	20.28	0.460
Third Quarter	26.80	20.91	0.455
Second Quarter	27.99	24.13	0.450
First Quarter	27.77	25.41	0.445

Cash Distribution Policy

We distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below. If we do not have sufficient cash to pay our distributions as well as satisfy our other operational and financial obligations, our General Partner has the ability to reduce or eliminate the distribution paid on our common units so that we may satisfy such obligations, including payments on our debt instruments.

Available cash generally means, for any quarter ending prior to liquidation of the Partnership, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the General Partner in respect of any one or more of the next four quarters.

In addition to distributions on its General Partner interest, our General Partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds specified levels. The partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- first, to all unitholders and to the General Partner, pro rata, until each unitholder receives a minimum quarterly distribution of $0.35 per unit outstanding for that quarter;
- second, to all unitholders and to the General Partner, pro rata, until each unitholder receives a total of $0.4025 per unit outstanding for that quarter;
- third, (i) to the General Partner in accordance with its percentage interest, (ii) 13% to holders of the IDRs, pro rata, and (iii) to all unitholders a percentage equal to 100% less the percentages applicable to the General Partner and holders of the IDRs, until each unitholder receives a total of $0.4375 per unit outstanding for that quarter;

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- fourth, (i) to the General Partner in accordance with its percentage interest, (ii) 23% to holders of the IDRs, pro rata, and (iii) to all unitholders a percentage equal to 100% less the percentages applicable to the General Partner and holders of the IDRs, until each unitholder receives a total of $0.5250 per unit outstanding for that quarter; and
- thereafter, (i) to the General Partner in accordance with its percentage interest, (ii) 48% to holders of the IDRs, pro rata, and (iii) to all unitholders a percentage equal to 100% less the percentages applicable to the General Partner and holders of the IDRs.

In each case, the amount of the distribution set forth above is exclusive of any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution.

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources” for further discussion regarding the restrictions on distributions.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

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Item 6. Selected Financial Data

The historical financial information presented below for the Partnership was derived from our audited consolidated financial statements as of and for the periods presented below. See "Item 7. Management's Discussions and Analysis of Financial Condition and Results of Operations" for a discussion of why our results may not be comparable, either from period to period or going forward. All tabular dollar amounts, except per unit data, are in millions.

	Successor			Predecessor		
	Year Ended December 31, 2012	Year Ended December 31, 2011	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Statement of Operations Data:						
Total revenues	$1,339	$1,434	$716	$505	$1,043	$1,785
Total operating costs and expenses	1,304	1,394	702	485	816	1,635
Operating income	35	40	14	20	227	150
Other income and deductions:						
Income from unconsolidated affiliates	114	120	54	16	8	—
Interest expense, net	(122)	(103)	(48)	(35)	(78)	(63)
Loss on debt refinancing, net	(8)	—	(16)	(2)	—	—
Other income and deductions, net	30	17	(8)	(4)	(15)	—
Income (loss) from continuing operations before income taxes	49	74	(4)	(5)	142	87
Income tax expense (benefit)	1	—	1	—	(1)	—
Income (loss) from continuing operations	$48	$74	$(5)	$(5)	$143	$87
Discontinued operations:						
Net (loss) income from operations of east Texas assets	—	—	(1)	—	(3)	14
Net income (loss)	48	74	(6)	(5)	140	101
Net income attributable to noncontrolling interest	(2)	(2)	—	—	—	—
Net income (loss) attributable to Regency Energy Partners LP	$46	$72	$(6)	$(5)	$140	$101
Amounts attributable to Series A Preferred Units	10	8	5	3	4	—
General partner's interest, including IDRs	9	7	3	1	5	4
	—	—	—	—	1	1

Amount allocated to non-vested common units						
Beneficial conversion feature for Class D common units	—	—	—	—	1	7
Limited partners' interest in net income (loss)	$27	$57	$(14)	$(9)	$129	$89
Basic and diluted income (loss) from continuing operations per unit:						
Basic income (loss) from continuing operations per common and subordinated unit	$0.16	$0.39	$(0.09)	$(0.10)	$1.63	$1.14
Diluted income (loss) from continuing operations per common and subordinated units	0.13	0.32	(0.09)	(0.10)	1.63	1.10
Distributions per common and subordinated unit	1.84	1.81	0.89	0.89	1.78	1.71

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Basic and diluted income (loss) on discontinued operations per unit	$—	$—	$(0.01)	$—	$(0.03)	$0.21
Basic and diluted net income (loss) per unit:						
Basic net income (loss) per common and subordinated unit	$0.16	$0.39	$(0.10)	$(0.10)	$1.61	$1.34
Diluted net income (loss) per common and subordinated unit	0.13	0.32	(0.10)	(0.10)	1.60	1.28
Income per Class D common unit due to beneficial conversion feature	$—	$—	$—	$—	$0.11	$0.99

	Successor December 31, 2012	December 31, 2011	December 31, 2010	Predecessor December 31, 2009	December 31, 2008
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$2,162	$1,886	$1,660	$1,456	$1,704
Total assets	6,157	5,568	4,770	2,533	2,459
Long-term debt (long-term portion only)	2,157	1,687	1,141	1,014	1,126
Series A Preferred Units	73	71	71	52	—
Partners' capital	3,610	3,531	3,294	1,243	1,099

	Successor			Predecessor		
	Year Ended December 31, 2012	Year Ended December 31, 2011	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash Flow Data:						
Net cash flows provided by (used in):						
Operating activities	$252	$254	$80	$89	$144	$181
Investing activities	(683)	(955)	(297)	(148)	(156)	(949)
Financing activities	483	693	203	72	21	735
Other Financial Data:						
Adjusted total segment margin[1]	$463	$421	$235	$154	$361	$402
Adjusted EBITDA[1]	480	422	218	108	211	259
Maintenance capital expenditures	34	22	7	8	20	18

(1) See "—Non-GAAP Financial Measures" for a reconciliation to its most directly comparable GAAP measure.

Non-GAAP Financial Measures

We include in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” the following non-GAAP financial measures: EBITDA, adjusted EBITDA, total segment margin, and adjusted total segment margin. We provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP.

We define EBITDA as net income (loss) plus interest expense, net, income tax expense, net, and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus or minus the following:

- non-cash loss (gain) from commodity and embedded derivatives;
- unit-based compensation expenses;
- loss (gain) on asset sales, net;
- loss on debt refinancing;
- other non-cash (income) expense, net;
- net income attributable to noncontrolling interest; and

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- our interest in adjusted EBITDA from unconsolidated affiliates less income from unconsolidated affiliates.

These measures are used as supplemental measures by our management and by external users of our financial statements such as investors, banks, research analysts and others, to assess:

- 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 pay interest costs, support our indebtedness and make cash distributions to our unitholders and General Partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Neither EBITDA and adjusted EBITDA should not be considered an alternative to, or more meaningful than net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA and adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA or adjusted EBITDA in the same manner. Adjusted EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded Partnership.

EBITDA and adjusted EBITDA do not include interest expense, income tax expense or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as EBITDA and adjusted EBITDA, to evaluate our performance.

We define segment margin, generally, as revenues minus cost of sales. We calculate our Gathering and Processing segment margin and Natural Gas Transportation segment margin as revenues generated from operations less the cost of natural gas and NGLs purchased and other costs of sales, including third-party transportation and processing fees. We do not record segment margin for our investments in unconsolidated affiliates (HPC, MEP, Lone Star and Ranch JV) because we record our ownership percentages of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting. We calculate our Contract Services segment margin as revenues minus direct costs, primarily compressor unit repairs, associated with those revenues. We calculate total segment margin as the sum of segment margin of our segments less intersegment eliminations. We define adjusted segment margin as segment margin adjusted for non-cash (gains) losses from commodity derivatives. Our adjusted total segment margin equals the sum of our operating segments' adjusted segment margins or segment margins, as applicable, including intersegment eliminations.

Total segment margin and adjusted total segment margin are included as a supplemental disclosure because they are primary performance measures used by our management as they represent the result of product sales, service fee revenues and product purchases, a key component of our operations. We believe total segment margin and adjusted total segment margin are important measures because they are directly related to our volumes and commodity price changes. Operation and maintenance expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operation and maintenance expenses. These expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. We do not deduct operation and maintenance expenses from total revenue in calculating total segment margin and adjusted total segment margin because we separately evaluate commodity volume and price changes in these margin amounts. As an indicator of our operating performance, total segment margin or adjusted total segment margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our total segment margin and adjusted total segment margin may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner.

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	Successor			Predecessor		
	Year Ended December 31, 2012	Year Ended December 31, 2011	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and to net income (loss)						
Net cash flows provided by operating activities	$252	$254	$80	$89	$144	$181
Add (deduct):						
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	(209)	(175)	(79)	(49)	(116)	(105)
Write-off of debt issuance costs and bond premium	1	—	1	(2)	—	—
Income from unconsolidated affiliates	114	120	54	16	8	—
Derivative valuation change	19	21	(33)	(12)	(5)	15
(Loss) gain on assets sales, net	(3)	2	—	—	133	(1)
Unit-based compensation expenses	(5)	(3)	(2)	(12)	(6)	(4)
Gain on insurance settlements	—	—	—	—	—	3
Trade accounts receivable, accrued revenues and related party receivables	(7)	8	—	11	(11)	(19)
Other current assets and other current liabilities	(4)	(11)	13	(25)	(4)	(6)
Trade accounts payable, accrued cost of gas and liquids, related party payables, and deferred revenues	10	(23)	15	(9)	4	41
Distributions received from unconsolidated affiliates	(121)	(119)	(57)	(12)	(8)	—
Other assets and liabilities	1	—	2	—	1	(4)
Net income (loss)	48	74	(6)	(5)	140	101
Add (deduct):						
Interest expense, net	122	103	48	35	78	63
Depreciation and amortization	201	169	77	46	110	103
Income tax expense (benefit)	1	—	1	—	(1)	—
EBITDA	372	346	120	76	327	267
Add (deduct):						
Non-cash (gain) loss from commodity and embedded derivatives	(19)	(18)	31	11	5	(15)

Unit-based compensation expenses	5	3	2	12	6	4
Loss (gain) on assets sales, net	3	(2)	—	—	(133)	1
Income from unconsolidated affiliates	(114)	(120)	(54)	(16)	(8)	—
Partnership's interest in unconsolidated affiliates adjusted EBITDA (1) (2) (3) (4)	227	213	102	21	11	—
Loss on debt refinancing, net	8	—	16	2	—	—
Other expense, net	(2)	—	1	2	3	2
Adjusted EBITDA	$480	$422	$218	$108	$211	$259
(1) 100% of HPC's Adjusted EBITDA is calculated as follows:						
Net income	$70	$109	$72	$35	$20	$—
Add:						
Depreciation and amortization	36	35	20	12	9	—
Interest expense	2	1	—	—	—	—
Impairment of property, plant and equipment	22	—	—	—	—	—
Other expense, net	2	—	—	—	—	—
HPC's Adjusted EBITDA	132	145	92	47	29	—
Ownership Interest	49.99%	49.99%	49.99%	45%	38%	—%
Partnership's interest in HPC's Adjusted EBITDA	$65	$72	$46	$21	$11	$—

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(2) 100% of MEP's EBITDA is calculated as follows:						
Net income	$83	$85	$43	$—	$—	$—
Add:						
Depreciation and amortization	69	70	40	—	—	—
Interest expense, net	52	51	29	—	—	—
MEP's Adjusted EBITDA	204	206	112	—	—	—
Ownership Interest	50 %	50 %	49 %	— %	— %	— %
Partnership's interest in MEP's Adjusted EBITDA	$102	$103	$56	$—	$—	$—
(3) 100% of Lone Star's Adjusted EBITDA is calculated as follows:						
Net income	$147	$94	$—	$—	$—	$—
Add:						
Depreciation and amortization	52	32	—	—	—	—
Lone Star's Adjusted EBITDA	199	126	—	—	—	—
Ownership Interest	30 %	30 %	— %	— %	— %	— %
Partnership's interest in Lone Star's Adjusted EBITDA	$60	$38	$—	$—	$—	$—
(4) 100% of Ranch JV's Adjusted EBITDA is calculated as follows:						
Net loss	$(2)	$—	$—	$—	$—	$—
Add:						
Depreciation and amortization	1	—	—	—	—	—
Ranch JV's Adjusted EBITDA	(1)	—	—	—	—	—
Ownership Interest	33.33 %	— %	— %	— %	— %	— %
Partnership's interest in Ranch JV's Adjusted EBITDA	$—	$—	$—	$—	$—	$—

	Successor			Predecessor		
	Year Ended December 31, 2012	Year Ended December 31, 2011	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Reconciliation of net income (loss) to "Adjusted total segment margin"						
Net income (loss)	$48	$74	$(6)	$(5)	$140	$101
Add (deduct):						
Operation and maintenance	166	147	78	48	117	120
General and administrative	63	67	44	37	57	51
Loss (gain) on assets sales, net	3	(2)	—	—	(133)	—
Management services termination fee	—	—	—	—	—	4
Transaction expenses	—	—	—	—	—	2
Depreciation and amortization	201	169	76	42	100	93

Income from unconsolidated affiliates	(114)	(120)	(54)	(16)	(8)	—
Interest expense, net	122	103	48	35	78	63
Loss on debt refinancing, net	8	—	16	2	—	—
Other income and deductions, net	(30)	(17)	8	4	15	—
Income tax expense (benefit)	1	—	1	—	(1)	—
Discontinued operations	—	—	1	—	3	(14)
Total segment margin	468	421	212	147	368	420
Add (deduct):						
Non-cash (gain) loss from commodity derivatives	(5)	—	23	7	(7)	(18)
Adjusted total segment margin	$463	$421	$235	$154	$361	$402

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our historical consolidated financial statements and notes included elsewhere in this document.

We are a growth-oriented publicly-traded Delaware limited partnership formed in 2005 engaged in the gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring, Avalon and Granite Wash shales. Our assets are primarily located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, New Mexico, and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma.

We divide our operations into five business segments. During the fourth quarter of 2012, the Partnership realigned the composition of its segments and updated the segment names to reflect the realignment. Accordingly, we have restated segment information for earlier periods to reflect this new segment alignment as follows:

- Gathering and Processing. We provide "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes our 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.
- Natural Gas Transportation. We own a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets, and a 50% membership interest in MEP, which owns an interstate natural gas pipeline with approximately 500 miles stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.
- NGL Services. We own a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in Texas, Mississippi and Louisiana.
- Contract Services. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.
- Corporate. The Corporate segment comprises our corporate offices.

Gathering and Processing segment. Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas that we gather and process, our current contract portfolio and natural gas and NGL prices. We measure the performance of this segment primarily by the adjusted segment margin it generates. We gather and process natural gas pursuant to a variety of arrangements generally categorized as "fee-based" arrangements, "percent-of-proceeds" arrangements and "keep-whole" arrangements. Under fee-based arrangements, we earn fixed cash fees for the services that we render. Under the latter two types of arrangements, we generally purchase raw natural gas and sell processed natural gas and NGLs. We regard the adjusted segment margin generated by our sales of natural gas and NGLs under percent-of-proceeds and keep-whole arrangements as comparable to the revenues generated by fixed fee arrangements to the extent that they are hedged.

Percent-of-proceeds and keep-whole arrangements involve commodity price risk to us because our adjusted segment margin is based in part on natural gas and NGL prices. We seek to minimize our exposure to fluctuations in commodity prices in several ways, including managing our contract portfolio. In managing our contract portfolio, we classify our gathering and processing contracts according to the nature of commodity risk implicit in the settlement structure of those contracts.

We also minimize our exposure to commodity price fluctuations by executing swap and put option contracts settled against ethane, propane, butane, natural gasoline, natural gas and WTI market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

In addition, we perform a producer services function whereby we purchase natural gas from producers or gas marketers at receipt points on our systems, including HPC, and transport that gas to delivery points on HPC's system at which we sell the natural gas at market price. We regard the segment margin with respect to those purchases and sales as the economic equivalent of a fee for our transportation service. These contracts are frequently settled in terms of an index price for both purchases and sales. In order to minimize commodity price risk, we attempt to match sales with purchases at the index price. We typically sell natural gas under pricing terms related to a market index. To the extent possible, we match the pricing and timing of our supply portfolio to our sales portfolio in order to lock in our margin and reduce our overall commodity price exposure. To the extent our natural gas position is not balanced, we will be exposed to the commodity price risk associated with the price of natural gas. Refer to “Item 7A. Quantitative and Qualitative Disclosure about Market Risk” for further details.

Natural Gas Transportation segment. HPC has the capacity to transport up to 2.1 Bcf/d of natural gas. Results of HPC’s operations are determined primarily by the volumes of natural gas transported and subscribed on its intrastate pipeline system and the level of fees charged to customers or the margins received from purchases and sales of natural gas. HPC generates revenues and segment margins principally under fee-based transportation contracts. Approximately 89% of the margin HPC earns is related to fixed capacity reservation charges that are not directly dependent on throughput volumes or commodity prices.

MEP pipeline system, operated by KMP, has the capability to transport up to 1.8 Bcf/d of natural gas, and the pipeline capacity is fully subscribed with long-term binding commitments from creditworthy shippers. Results of MEP’s operations are determined primarily by the volumes of natural gas transported and subscribed on its interstate pipeline system and the level of fees charged to customers. MEP generates revenues and segment margins principally under fee-based transportation contracts. The margin MEP earns is primarily related to fixed capacity reservation charges that are not directly dependent on throughput volumes or commodity prices. If a sustained decline in commodity prices should result in a decline in volumes, MEP’s revenues would not be significantly impacted until expiration of the current contracts.

Gulf States is a small interstate pipeline that uses cost-based rates and terms and conditions of service for shippers wishing to secure capacity for interstate transportation service. Rates charged are largely governed by long-term negotiated rate agreements.

NGL Services segment. Lone Star owns and operates a NGLs storage, fractionation and transportation business. Lone Star's storage assets are primarily located in Mont Belvieu, Texas and its West Texas Pipeline, which passes through the Barnett shale, and its Lone Star West Texas Gateway NGL Pipeline, which passes through the Eagle Ford shale, transport NGLs through intrastate pipeline systems that originate in the Permian and Delaware basins in west Texas, and terminate at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana and Texas, including the Lone Star Fractionator I, located at Mont Belvieu, which began service in December 2012. Results of Lone Star's operations are based upon fee-based revenues and commodity pricing which are determined primarily by volumes stored, processed or transported, the level of fees charged to customers and the value of the commodity in the market at the time of sale. The margin Lone Star earns is primarily related to the volume of NGLs stored, processed and transported.

Contract Services segment. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management. Fees charged for compression and treating services are typically fixed and are based on the revenue generating horsepower.

HOW WE EVALUATE OUR OPERATIONS. Management uses a variety of financial and operational measurements to analyze our performance. We view these measures as important tools for evaluating the success of our operations and review these measurements on a monthly basis for consistency and trend analysis. These measures include volumes, segment margin, total segment margin, adjusted segment margin, adjusted total segment margin, revenue generating horsepower and operation and maintenance expense on a segment and company-wide basis and EBITDA and adjusted EBITDA on a company-wide basis.

Volumes. We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is affected by (i) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our gathering and processing systems, (ii) our ability to compete for volumes from successful new wells in other areas and (iii) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

Segment Margin and Total Segment Margin. We define segment margin, generally, as revenues minus cost of sales. We calculate our Gathering and Processing segment margin and Natural Gas Transportation segment margin as our revenues generated from operations less the cost of natural gas and NGLs purchased and other cost of sales, including third-party transportation and processing fees.

We do not record segment margin for our investments in unconsolidated affiliates (HPC, MEP, Lone Star, and Ranch JV) because we record our ownership percentage of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

We calculate our Contract Services segment margin as our revenues generated from our contract compression and treating operations minus direct costs, primarily repairs, associated with those revenues.

We calculate total segment margin as the total of segment margin of our five segments, less intersegment eliminations.

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Adjusted Segment Margin and Adjusted Total Segment Margin. We define adjusted segment margin as segment margin adjusted for non-cash (gains) losses from commodity derivatives. Our adjusted total segment margin equals the sum of our operating segments' adjusted segment margins or segment margins, including intersegment eliminations. Adjusted segment margin and adjusted total segment margin are included as supplemental disclosures because they are primary performance measures used by management as they represent the results of product purchases and sales, a key component of our operations.

Revenue Generating Horsepower. Revenue generating horsepower is the primary driver for revenue growth in our contract compression segment, and it is also the primary measure for evaluating our operational efficiency. Revenue generating horsepower is the total horsepower that our Contract Services segment owns and operates for external customers. It does not include horsepower under contract that is not generating revenue or idle horsepower.

Operation and Maintenance Expense. Operation and maintenance expense is a separate measure that we use to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating and maintenance expense. These expenses are largely independent of the volumes through our systems but fluctuate depending on the activities performed during a specific period. We do not deduct operation and maintenance expenses from total revenues in calculating segment margin because we use segment margin to separately evaluate commodity volume and price changes.

EBITDA and Adjusted EBITDA. We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus or minus the following:

- non-cash loss (gain) from commodity and embedded derivatives;
- non-cash unit-based compensation;
- loss (gain) on asset sales, net;
- loss on debt refinancing;
- other non-cash (income) expense, net;
- net income attributable to noncontrolling interest; and
- our interest in adjusted EBITDA from unconsolidated affiliates less income from unconsolidated affiliates.

These measures are used as supplemental measures by our management and by external users of our financial statements such as investors, banks, research analysts and others, to assess:

- 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 pay interest costs, support our indebtedness and make cash distributions to our unitholders and General Partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Neither EBITDA nor adjusted EBITDA should be considered as an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA and adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA or adjusted EBITDA in the same manner. Adjusted EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded partnership.

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

Energy Outlook. In its annual energy outlook forecast, the EIA projects that domestic production of crude oil will increase from an average of 5.6 million Bbls/d in 2011 to 7.9 million Bbls/d by 2014, a 40% increase. Although production is projected to gradually decline beyond 2020, overall crude production is expected to remain above 6.1

million Bbls/d through 2040.

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Natural gas production from shales is expected to increase to 19 trillion cubic feet by 2040 from 5 trillion cubic feet produced in 2010. Natural gas production from shales amounted to 23% of total natural gas produced in the U.S. in 2010 and is projected to grow to 56% by 2040.

The increase in natural gas consumption is expected to come primarily from the industrial and electric power sectors. Natural gas used in the industrial sector is projected to grow from 6.8 trillion cubic feet in 2011 to 7.8 trillion cubic feet in 2025. The natural gas share of electricity generation rose to 24% in 2010 and is expected to continue increasing to 30% in 2040.

Recently, however, as drilling activities have been more focused on shale plays with a high concentration of NGLs and crude oil, some producers have announced plans to reduce gas drilling activities in order to focus on oil and NGLs prospects.

Effect of Interest Rates and Inflation. Interest rates on existing and future credit facilities and future debt offerings could be significantly higher than current levels, causing our financing costs to increase accordingly. Although increased financing costs could limit our ability to raise funds in the capital markets, we expect to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and has not had a material effect on our results of operations. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by price changes in natural gas and NGLs. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along a portion of increased costs to our customers in the form of higher fees.

RECENT DEVELOPMENTS

SUGC. In February 2013, we and Regency Western entered into a contribution agreement with Southern Union, a wholly owned subsidiary of Holdco, to acquire SUGC for $1.5 billion, subject to customary post-closing adjustments. We will finance the acquisition by issuing $900 million of common units to Holdco, comprised of $750 million of our common units and $150 million of recently created Class F common units. The Class F common units are entitled to participate in our distributions for twenty-four months post-transaction closing. The remaining $600 million will be paid in cash. In addition, in conjunction with the acquisition, ETE has agreed to forgo IDR payments on the common units issued with this transaction for the twenty-four months post-transaction closing and to eliminate the $10 million annual management fee paid by us for two years post-transaction close. The transaction is expected to close in the second quarter of 2013.

Upon closing, the acquisition of SUGC will expand our presence is the Permian Basin in west Texas, one of the most prolific, high growth, oil and liquids-rich basins in North America.

Because the SUGC acquisition is a transaction between commonly controlled entities (i.e., the buyer and the sellers are each affiliates of ETE), we will be required to account for the acquisition in a manner similar to the pooling of interest method of accounting. Under this method of accounting, the SUGC acquisition will reflect historical balance sheet data for both SUGC and us instead of reflecting the fair market value of SUCG assets and liabilities. We will recast our financial statements to include the operations of SUGC from March 26, 2012 (the date upon which common control began).

Eagle Ford Expansion. In May 2012, we announced the construction of an expansion to ELG in the Eagle Ford shale ("Edwards Lime Expansion") which will increase the system's capacity by 90 MMcf/d to 160 MMcf/d, and will provide for additional crude transportation and stabilization capacity of 17,000 Bbls/d. We own a 60% interest in ELG and operate the assets. Contracts on the expansion are fee-based, which includes reservation fees. Capital expenditures related to the expansion are expected to total $150 million, of which we will contribute $90 million; this amount is included in our previously announced 2012 growth capital projections. The project is expected to be completed in the first half of 2013.

Dubach Processing Facility Expansion. In August 2012, we announced an expansion of the Dubach processing facility in north Louisiana which will increase the processing capacity of the facility to 210 MMcf/d by adding an incremental 70 MMcf/d of cryogenic processing capacity and 20 MMcf/d of JT capacity. The $75 million capital expenditure related to the Dubach expansion also includes the construction of high-pressure gathering lines to transport production to the facility. The project, which is expected to come online in the second quarter of 2013, is backed by fee-based contracts and an acreage dedication.

Lone Star Expansion. In February 2012, Lone Star announced it would construct a second 100,000 Bbls/d NGL fractionation facility at Mont Belvieu, Texas. Lone Star expects this second fractionator to be completed in the fourth quarter of 2013 at an estimated cost of $350 million, of which our proportionate estimated capital contributions is $105 million. In December 2012, Lone Star announced that its West Texas Gateway NGL Pipeline and Lone Star Fractionator I were placed in service, both before originally anticipated. The West Texas Gateway NGL Pipeline, which passes through the Eagle Ford shale, is a 570-mile, 16-inch pipeline that transports NGLs produced in the Permian and Delaware Basins in West Texas to Mont Belvieu, Texas and has an

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initial capacity of 209,000 Bbls/d. The Fractionator I, located at Mont Belvieu, Texas, has a capacity of 100,000 barrels per day of NGLs and will handle NGL barrels delivered from several sources, including the West Texas Gateway NGL pipeline.

Ranch JV Expansion. In June 2012, Ranch JV's 25 MMcf/d refrigeration processing plant began operations. In December 2012, Ranch JV’s 100 MMcf/d cryogenic processing plant began operations.

RESULTS OF OPERATIONS

Year Ended December 31, 2012 vs. Year Ended December 31, 2011

(Tabular dollar amounts, except per unit data, are in millions)

	Year Ended December 31, 2012	Year Ended December 31, 2011	Change	Percent
Total revenues	$1,339	$1,434	$(95)	7 %
Cost of sales	871	1,013	(142)	14
Total segment margin (1)	468	421	47	11
Operation and maintenance	166	147	19	13
General and administrative	63	67	(4)	6
Loss (gain) on asset sales, net	3	(2)	5	250
Depreciation and amortization	201	169	32	19
Operating income	35	40	(5)	13
Income from unconsolidated affiliates	114	120	(6)	5
Interest expense, net	(122)	(103)	(19)	18
Loss on debt refinancing, net	(8)	—	(8)	100
Other income and deductions, net	30	17	13	76
Income before income taxes	49	74	(25)	34
Income tax expense	1	—	1	100
Net income	$48	$74	$(26)	35
Net income attributable to the noncontrolling interest	(2)	(2)	—	—
Net income attributable to Regency Energy Partners LP	$46	$72	$(26)	36 %
Gathering and processing segment margin	$279	$233	$46	20 %
Non-cash gain from commodity derivatives	(5)	—	(5)	100
Adjusted gathering and processing segment margin	$274	$233	$41	18
Natural gas transportation segment margin	2	3	(1)	33
Contract services segment margin (2)	189	185	4	2
Corporate segment margin	19	17	2	12
Intersegment eliminations (2)	(21)	(17)	(4)	24
Adjusted total segment margin	$463	$421	$42	10 %

(1) For reconciliation of segment margin to the most directly comparable financial measure calculated and presented in accordance with GAAP, read “Item 6. Selected Financial Data.”

(2) Contract Services segment margin includes intersegment revenues of $21 million and $17 million for the years ended December 31, 2012 and 2011, respectively. These intersegment revenues were eliminated upon consolidation.

Net Income Attributable to Regency Energy Partners LP. Net income attributable to Regency Energy Partners LP decreased to $46 million in the year ended December 31, 2012 from $72 million in the year ended December 31, 2011. The major components of this change were as follows:

- $47 million increase in total segment margin mainly due to increased volumes in south and west Texas and north Louisiana in our Gathering and Processing segment. Although the decline in commodity prices lowered revenues and cost of sales, it had little impact to our total segment margin, as we continue to grow our fee-based revenues in south and west Texas as well as north Louisiana;

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- $13 million increase in other income and deductions, net, primarily due to a $16 million one-time producer payment received in March 2012 related to an assignment of certain contracts offset by a decrease in the non-cash gain on the embedded derivatives related to the Series A Preferred Units; and
- $4 million decrease in general and administrative expenses primarily due to lower professional fees and office expenses; offset by
- $32 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects placed in service during 2012, as well as a $12 million increase related to the accelerated depreciation and amortization of certain tangible and intangible assets and an out-of-period adjustment of $7 million recorded in March 2012 (further discussed below);
- $19 million increase in operations and maintenance expense primarily related to increases in employee costs, compressor maintenance costs, and ad valorem taxes due to growth in west and south Texas and north Louisiana;
- $19 million increase in interest expense, net, primarily related to a full year of interest associated with the $500 million 2021 Notes issued in May 2011 as well as three months of interest associated with our $700 million 2023 notes issued in October 2012;
- $8 million net loss on debt refinancing related to the redemption of 35% of our outstanding 2016 Notes at a price of 109.375% of the principal amount plus accrued interest in May 2012; and
- $6 million decrease in income from unconsolidated affiliates primarily related to a decrease in equity income from HPC associated with non-cash asset impairment charges related to its idle property, plant, and equipment.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $463 million in the year ended December 31, 2012 from $421 million in the year ended December 31, 2011. The major components of this increase were as follows:

- Adjusted Gathering and Processing segment margin increased to $274 million for the year ended December 31, 2012 from $233 million for the year ended December 31, 2011 primarily due to the volume growth in south and west Texas and north Louisiana. Total Gathering and Processing segment throughput increased to 1,433,000 MMBtu/d during the year ended December 31, 2012 from 1,187,000 MMBtu/d during the year ended December 31, 2011. Total NGL gross production increased to 38,000 Bbls/d during the year ended December 31, 2012 from 32,000 Bbls/d during the year ended December 31, 2011;
- Contract Services segment margin increased to $189 million in the year ended December 31, 2012 from $185 million in 2011. Contract Services segment margin includes both revenues from external customers as well as intersegment revenues and is primarily based on revenue generating horsepower. Revenue generating horsepower, inclusive of intersegment revenue generating horsepower, increased to 919,000 as of December 31, 2012 from 846,000 as of December 31, 2011. The increase in revenue generating horsepower is primarily attributable to additional horsepower placed into service in south Texas for the Gathering and Processing segment to provide compression services to third party customers;
- Corporate segment margin increased to $19 million in the year ended December 31, 2012 from $17 million in the year ended December 31, 2011, which was primarily attributable to the increase in the management fee received from HPC beginning in April 2012; and
- Intersegment eliminations increased to $21 million in the year ended December 31, 2012 from $17 million in the year ended December 31, 2011. The increase was primarily due to an increase in transactions between Gathering and Processing and the Contract Services segments as a result of additional services provided in south Texas for the Gathering and Processing segment to provide compression and treating services to external customers.

Operation and Maintenance. Operation and maintenance expense increased to $166 million in the year ended December 31, 2012 from $147 million in the year ended December 31, 2011. The increase is primarily due to the following:

- $8 million increase in employee expenses for organic growth projects in south and west Texas and an increase in employee headcount;
- $5 million increase in compressor maintenance costs primarily related to an increase in materials and maintenance costs; and
- $5 million increase in ad valorem taxes primarily related to our organic growth projects.

General and Administrative. General and administrative expense decreased to $63 million in the year ended December 31, 2012 from $67 million in the year ended December 31, 2011. This decrease is primarily the result of the following:

- $3 million decrease in professional fees associated with decreases in legal and consulting fees; and

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- $2 million decrease in office expenses related to lower rent expenses; offset by
- $2 million increase in employee expenses, including primarily management incentive plan expenses and benefits.

Depreciation and Amortization. Depreciation and amortization expense increased to $201 million in the year ended December 31, 2012 from $169 million in the year ended December 31, 2011. This increase was the result of $13 million of additional depreciation and amortization expense due to the completion of various organic growth projects since December 2011, a $12 million increase related to the acceleration of depreciation and amortization of certain tangible and intangible assets that management determined had shorter economic useful lives, and a $7 million increase related to an “out-of-period” adjustment for all periods subsequent to May 26, 2010 (the “Successor” period) related to our Contract Services segment to adjust the estimated useful lives of certain assets to comply with our policy. The amounts associated with the out-of-period adjustment related to the year ended December 31, 2011 and to the period from May 26, 2010 to December 31, 2010 were $4 million and $3 million, respectively. Had these amounts been recorded to their respective period, the depreciation and amortization expense for the year ended December 31, 2012 and 2011 would have been $194 million and $173 million, respectively.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates decreased to $114 million for the year ended December 31, 2012 from $120 million for the year ended December 31, 2011. The schedule summarizes the components of income from unconsolidated affiliates and our ownership interest for the years ended December 31, 2012 and 2011, respectively:

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income (loss)	$70	$83	$147	(2)	
Ownership interest	49.99%	50%	30%	33.33%	
Share of unconsolidated affiliates’ net income (loss)	35	42	44	(1)	
Less: Amortization of excess fair value of unconsolidated affiliates	(6)	—	—	—	
Income (loss) from unconsolidated affiliates	$29	$42	$44	$(1)	$114
	Year Ended December 31, 2011				
	HPC	MEP(1)	Lone Star(2)	Ranch JV(3)	Total
Net income	$109	$85	$94	$—	
Ownership interest	49.99%	50%	30%	33.33%	
Share of unconsolidated affiliates’ net income	55	43	28	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(6)	—	—	—	
Income from unconsolidated affiliates	49	43	28	—	120

(1) Ownership interest in MEP increased to 50% in September 2011 due to the purchase of an additional 0.1% interest.
(2) Represents Lone Star net income from May 2, 2011 (date of acquisition) to December 31, 2011.
(3) We acquired a 33.33% membership interest in Ranch JV in December 2011.

HPC’s net income decreased to $70 million for the year ended December 31, 2012 from $109 million for the year ended December 31, 2011, primarily due to a $22 million non-cash asset impairment charge related to its surplus equipment acquired during the RIGS' 2009 Haynesville Expansion Project and not anticipated to be utilized in future expansion projects. In addition, HPC's margin decreased by $10 million year-over-year, mainly due to the expiration of certain contracts not renewed and lower throughput. Shippers who are choosing not to renew their contracts are primarily doing so because they hold excess firm transportation capacity out of the Haynesville shale. This excess capacity is a result of moving drilling rigs out of the Haynesville area to richer gas plays, which has slowed supply growth and contributed to the decrease in throughput.

MEP's net income decreased to $83 million for the year ended December 31, 2012 from $85 million for the year ended December 31, 2011. Lone Star's net income increased to $147 million from $94 million, due to its net income in the prior year only reflecting the activity from initial contribution, May 2, 2011 to December 31, 2011.

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The following table presents operational data for each of our unconsolidated affiliates for the years ended December 31, 2012 and 2011:

		Year Ended December 31,		
		2012	2011	
HPC	Throughput (MMBtu/d)	854,388	1,321,266	
MEP	Throughput (MMBtu/d)	1,409,079	1,360,658	
Lone Star	West Texas Pipeline – Total Volumes (Bbls/d)	134,274	130,246	(1)
	Refinery Services – Geismar Throughput (Bbls/d)	17,152	15,676	(1)
Ranch JV	Throughput (MMBtu/d) (2)	3,274	N/A	

(1) All of Lone Star's operational volumes represent the period from May 2, 2011 (acquisition date) to December 31, 2011.

(2) Ranch JV began operations in June 2012.

N/A: We acquired a 33.33% membership interest in Ranch JV in December 2011.

Interest Expense, net. Interest expense, net increased to $122 million in the year ended December 31, 2012 from $103 million in the year ended December 31, 2011. The increase was primarily attributable to a full year of interest associated with the $500 million 2021 Notes issued in May 2011 as well as three months of interest associated with the $700 million 2023 Notes issued in October 2012.

Other Income and Deductions, net. Other income and deductions, net increased to a $30 million gain in the year ended December 31, 2012 from a $17 million gain in the year ended December 31, 2011 primarily due to a $16 million one-time producer payment received in March 2012 related to an assignment of certain contracts, offset by a decrease in the non-cash mark-to-market gain in the embedded derivative related to the Series A Preferred Units.

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Year Ended December 31, 2011 vs. Combined Year Ended December 31, 2010
(Tabular dollar amounts, except per unit data, are in millions)

		Combined Year Ended December 31, 2010				
	Successor		Predecessor			
	Year Ended December 31, 2011	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to May 25, 2010	Combined Year Ended December 31, 2010	Change	Percent
Total revenues	$1,434	$716	$ 505	$1,221	$213	17 %
Cost of sales	1,013	504	358	862	151	17
Total segment margin [1]	421	212	147	359	62	17
Operation and maintenance	147	78	48	126	21	18
General and administrative	67	44	37	81	(14)	17
Gain on asset sales, net	(2)	—	—	—	(2)	100
Depreciation and amortization	169	76	42	118	51	43
Operating income	40	14	20	34	6	18
Income from unconsolidated subsidiaries	120	54	16	70	50	72
Interest expense, net	(103)	(48)	(35)	(83)	(20)	24
Loss on debt refinancing, net	—	(16)	(2)	(18)	18	100
Other income and deductions, net	17	(8)	(4)	(12)	29	243
Income (loss) from continuing operations before income taxes	74	(4)	(5)	(9)	83	983
Income tax expense	—	1	—	1	(1)	51
Net income (loss) from continuing operations	74	(5)	(5)	(10)	84	888
Discontinued operations	—	(1)	—	(1)	1	100
Net income (loss)	$74	$(6)	$ (5)	$(11)	$85	774
Net income attributable to the noncontrolling interest	(2)	—	—	—	(2)	100
Net income (loss) attributable to Regency Energy Partners LP	$72	$(6)	$ (5)	$(11)	$83	731 %
Gathering and processing segment margin	$233	$110	$ 86	$196	$37	19 %
Non-cash loss from commodity derivatives	—	23	7	30	(30)	100
Adjusted gathering and processing segment margin	$233	$133	$ 93	$226	$7	3
Natural gas transportation segment margin	3	3	1	4	(1)	25
Contract services segment margin [2]	185	103	62	165	20	12
Corporate segment margin	17	10	7	17	—	—

Intersegment eliminations [2]	(17)	(14)	(9)	(23)	6	26
Adjusted total segment margin	$421	$235	$ 154	$389	$32	8 %

(1) For reconciliation of segment margin to the most directly comparable financial measure calculated and presented in accordance with GAAP, read "Item 6. Selected Financial Data."

(2) Contract Services segment margin includes intersegment revenues of $17 million and $23 million for the years ended December 31, 2011 and 2010, respectively. These intersegment revenues were eliminated upon consolidation.

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Net (Loss) Income Attributable to Regency Energy Partners LP. Net income (loss) attributable to Regency Energy Partners LP increased to a net income of $72 million in the year ended December 31, 2011 from a net loss of $11 million in the year ended December 31, 2010. The major components of this change were as follows:

- $62 million increase in total segment margin mainly due to increased volumes in south Texas and a full year of treating services within our Contract Services segment margin, which were acquired in September 2010;
- $50 million increase in income from unconsolidated affiliates primarily from our acquisitions of a 49.9% interest in MEP in May 2010 and a 30% interest in Lone Star in May 2011;
- $29 million increase in other income and deductions, net due to the non-cash gain on the embedded derivatives related to the Series A Preferred Units;
- the absence of an $18 million redemption premium paid in 2010 and recorded as a loss on debt refinancing, net;
- $14 million decrease in general and administrative expenses primarily due to the absence of a $10 million one-time charge of unit-based compensation expense in 2010 related to the vesting of outstanding LTIP grants upon the acquisition of our General Partner by ETE; offset by
- $51 million increase in depreciation and amortization expense primarily related to additional assets placed in service during 2011 and a full year of depreciation related to the fair value adjustment of our long-lived assets upon the acquisition of our General Partner;
- $21 million increase in operations and maintenance expense primarily due to increased compression and pipeline maintenance as well as a full year of operations of treating services within our Contract Services segment, which were acquired in September 2010; and
- $20 million increase in interest expense, net, primarily related to the interest associated with the $500 million 2021 Notes issued in May 2011 to partially fund the acquisition of our 30% interest in Lone Star as well as a full year of interest associated with the $600 million 2018 Notes issued in October 2010.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $421 million in the year ended December 31, 2011 from $389 million in the year ended December 31, 2010. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $233 million for the year ended December 31, 2011 from $226 million for the year ended December 31, 2010 primarily due to the increased volumes in the Eagle Ford shale in south Texas and Permian Delaware Basin in west Texas. Total Gathering and Processing segment throughput increased to 1,187,000 MMBtu/d during the year ended December 31, 2011 from 996,800 MMBtu/d during the year ended December 31, 2010. Total NGL gross production increased to 32,000 Bbls/d during the year ended December 31, 2011 from 26,000 Bbls/d during the year ended December 31, 2010;
- Contract Services segment margin increased to $185 million in the year ended December 31, 2011 from $165 million in the year ended December 31, 2010. The increase was primarily attributable to the increased revenue generating horsepower provided to third parties as well as a full year of margin contributed from our treating services, which were acquired in September 2010. As of December 31, 2011, total revenue generating horsepower was 846,000, compared to 845,000 as of December 31, 2010; and
- Intersegment eliminations decreased to $17 million in the year ended December 31, 2011 from $23 million in the year ended December 31, 2010. The decrease was due to decreased intersegment transactions between the Gathering and Processing and the Contract Compression segment as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011.

Operation and Maintenance. Operation and maintenance expense increased to $147 million in the year ended December 31, 2011 from $126 million in the year ended December 31, 2010. The increase is primarily due to the following:

- $7 million increase in compressor maintenance costs primarily related to an increase in lube oil and materials costs;
- $6 million increase in pipeline maintenance expenses in our Gathering and Processing segment;
- $3 million increase in employee expenses primarily due to higher short-term incentive compensation accrual;
- $3 million increase in plant operating expenses primarily related to our contract treating services within our Contract Services segment, which was acquired in September 2010; and
- $2 million increase in consumable products.

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General and Administrative. General and administrative expense decreased to $67 million in the year ended December 31, 2011 from $81 million in the year ended December 31, 2010. This increase is primarily due to the following: