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 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, 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 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

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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 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 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

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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.

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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 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

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

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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)

	Successor	Combined Year Ended December 31, 2010				
			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:

- $13 million decrease in employee costs primarily due to the shared services integration and resulting reduction in headcount; and
- the absence of $10 million one-time charge in unit-based compensation primarily related to the vesting of outstanding LTIP grants upon the acquisition of our General Partner by ETE in May 2010; offset by
- $11 million increase in related party general and administrative expenses for the services agreements with Services Co. and ETC.

Depreciation and Amortization. Depreciation and amortization expense increased to $169 million in the year ended December 31, 2011 from $118 million in the year ended December 31, 2010. This increase was the result of $35 million of additional depreciation and amortization expense due to the completion of various organic growth projects since December 2010 and a $9 million increase related to our treating assets within the Contract Services segment that we acquired in September 2010. Additionally, there was a $8 million increase in depreciation and amortization expense incurred related to the increase of property, plant and equipment amounts resulting from the fair value adjustments upon the change in control resulting from the acquisition of our General Partner in May 2010. Had the change in control occurred on January 1, 2010, our depreciation and amortization expense on a pro forma basis for the combined year ended December 31, 2010 would have been $125 million.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $120 million for the year ended December 31, 2011 from $70 million for the year ended December 31, 2010. The schedule summarizes the components of income from unconsolidated affiliates and our ownership interest for the years ended December 31, 2011 and 2010, respectively:

	Year Ended December 31, 2011			
	HPC	MEP	Lone Star[4]	Total
Net income	$109	$85	$94	
Ownership interest	49.99%	50%[1]	30%	
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
	Year Ended December 31, 2010			
	HPC	MEP[2]	Lone Star	Total
Net income	$107	$43	N/A	
Ownership interest	48.3%[3]	49.9%	N/A	
Share of unconsolidated affiliates' net income	51	22	N/A	
Less: Amortization of excess fair value of unconsolidated affiliates	(3)	—	N/A	
Income from unconsolidated affiliates	$48	$22	N/A	$70

(1) Ownership interest in MEP increased to 50% in September 2011 due to the purchase of an additional 0.1% interest.
(2) Represents the MEP net income from May 26, 2010 (date of acquisition) to December 31, 2010.
(3) Ownership interest in HPC increased from 43% to 49.99% on April 30, 2010.
(4) Represents Lone Star net income from May 2, 2011 (date of acquisition) to December 31, 2011.
N/A: We acquired a 30% membership interest in Lone Star on May 2, 2011.

HPC's net income increased to $109 million for the year ended December 31, 2011 from $107 million for the year ended December 31, 2010, primarily due to higher throughput in 2010. Throughput increased to 1,321,000 MMBtu/d for the year ended December 31, 2011 from 1,278,000 MMBtu/d for the year ended December 31, 2010.

MEP's net income increased to $85 million for the year ended December 31, 2011 from $43 million for the period from May 26, 2010 (acquisition date) to December 31, 2010, primarily due to reporting a full year of operations.

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The following table presents operational data for each of our unconsolidated affiliates for the years ended December 31, 2011 and 2010:

		Year Ended December 31,			
		2011		2010	
HPC	Throughput (MMBtu/d)	1,321,266		1,277,881	
MEP	Throughput (MMBtu/d)	1,360,658		1,408,778	(2)
Lone Star	West Texas Pipeline – Total Volumes (Bbls/d)	130,246	(1)	N/A	
	Refinery Services – Geismar Throughput (Bbls/d)	15,676	(1)	N/A	

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

(2) Despite the decrease in throughput, MEP's revenues remained relatively stable throughout the period, because almost all of MEP's revenues are derived from firm transportation contracts with fixed fees.

N/A: We acquired a 30% membership interest in Lone Star on May 2, 2011.

Interest Expense, Net. Interest expense, net increased to $103 million in the year ended December 31, 2011 from $83 million in the year ended December 31, 2010. The increase was primarily attributable to interest associated with the $500 million 2021 Notes issued in May 2011 and a full year of interest associated with the $600 million 2018 Notes issued in October 2010.

Other Income and Deductions, net. Other income and deductions, net increased to a $17 million gain in 2011 from a $12 million loss in 2010 primarily due to the non-cash value change in the embedded derivatives related to the Series A Preferred Units issued in September 2009.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity will include:

- cash generated from operations and occasional asset sales;
- borrowings under our revolving credit facility;
- distributions received from unconsolidated affiliates;
- debt offerings; and
- issuance of additional partnership units.

We expect our 2013 capital expenditures, including capital contributions to our unconsolidated affiliates, to be as follows (in millions):

	2013
Growth Capital Expenditures	
Gathering and Processing segment	$365
NGL Services segment	120
Contract Services segment	95
Total	$580
Maintenance Capital Expenditures, including our proportionate share related to our unconsolidated affiliates	$50

We may revise the timing of these expenditures as necessary to adapt to economic conditions. We expect to fund our growth capital expenditures with borrowings under our revolving credit facility and a combination of debt and equity issuances.

Working Capital (Deficit) Surplus. Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our obligations as they become due. When we incur growth capital expenditures, we may experience working capital deficits as we fund construction expenditures out of working capital until they are permanently financed. Our working

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capital is also influenced by the fair value changes of current derivative assets and liabilities. These derivative assets and liabilities represent our expectations for the settlement of derivative rights and obligations over the next 12 months, and should be viewed differently from trade accounts receivable and accounts payable, which settle over a shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect derivative assets and liabilities to affect our ability to pay expenditures and obligations as they come due. Our Contract Services segment records deferred revenue as a current liability. The deferred revenue represents billings in advance of services performed. As the revenues associated with the deferred revenue are earned, the liability is reduced.

Our working capital deficit increased to $50 million at December 31, 2012 from a deficit of $46 million at December 31, 2011. This increase was primarily due to the following:

- an increase of $33 million in trade accounts payable net of trade accounts receivable, primarily due to the timing of payments and accruals for operating expenses and capital projects;
- an increase of $24 million in related party payables, primarily due to an accrual of $23 million capital contribution to Lone Star; offset by
- an increase of $52 million in cash and cash equivalents, primarily due to the capital contributions to ELG from its joint venture partners to fund its capital expansion projects.

Cash Flows from Discontinued Operations. We combined the cash flows from discontinued operations with the cash flows from continuing operations. The cash flows from discontinued operations related to our operating, investing and financing activities were insignificant. We do not expect the absence of cash flows from these discontinued operations will have a significant impact on our future liquidity.

Cash Flows from Operating Activities. Net cash flows provided by operating activities decreased to $252 million in the year ended December 31, 2012 from $254 million in the year ended December 31, 2011. Net cash flows provided by operating activities increased to $254 million in the year ended December 31, 2011 from $169 million in the year ended December 31, 2010. The increase was primarily due to an increase in distributions from unconsolidated affiliates and an increase in segment margin.

For all periods, we used our cash flows from operating activities together with borrowings under our credit facility to fund our working capital requirements, which include operation and maintenance expenses, maintenance capital expenditures and repayment of working capital borrowings. From time to time during each period, the timing of receipts and disbursements require us to borrow under our revolving credit facility.

Cash Flows used in Investing Activities. Net cash flows used in investing activities decreased to $683 million in the year ended December 31, 2012 from $955 million in the year ended December 31, 2011, which was primarily due to larger capital contributions made to Lone Star in 2011.

Net cash flows used in investing activities increased to $955 million in the year ended December 31, 2011 from $445 million in the year ended December 31, 2010. The increase was primarily due to the acquisition of a 30% interest in Lone Star in May 2011 for $594 million, offset by an increase in return of investment from unconsolidated affiliates of $15 million.

Growth Capital Expenditures. Growth capital expenditures are capital expenditures made to acquire additional assets to increase our business, to expand and upgrade existing systems and facilities or to construct or acquire similar systems or facilities. In the year ended December 31, 2012, we incurred $767 million of growth capital expenditures. Growth capital expenditures for the year ended December 31, 2012 consisted of $298 million for organic growth projects in our Gathering and Processing segment; $318 million for organic growth projects of Lone Star in NGL Services segment; and $151 million for the fabrication of new compressor packages and new treating plants for our Contract Services segment.

Maintenance Capital Expenditures. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets or to maintain the existing operating capacity of our assets and extend their useful lives. In the year ended December 31, 2012 and 2011, we incurred $34 million and $22 million, respectively, of maintenance capital expenditures, including our proportionate share related to unconsolidated affiliates.

Cash Flows from Financing Activities. Net cash flows provided by financing activities decreased to $483 million in the year ended December 31, 2012 from $693 million in the year ended December 31, 2011. The decrease was primarily due to a decrease in proceeds from common unit offerings of $124 million, an $88 million senior notes redemption in 2012, and an increase in partner distributions of $48 million.

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Net cash flows provided by financing activities increased to $693 million in the year ended December 31, 2011 from $275 million in the year ended December 31, 2010. The increase was primarily due to the following:

- the absence in 2011 of $358 million related to the redemption of our 2013 Senior Notes;
- a net increase in our revolving credit facility borrowings of $182 million; partially offset by
- an increase in Partner distributions of $70 million.

Capital Resources

Description of Our Indebtedness. As of December 31, 2012, our aggregate outstanding indebtedness totaled $2.16 billion and consisted of $192 million borrowings under our revolving credit facility and $1.97 billion of outstanding senior notes as compared to our aggregate outstanding indebtedness as of December 31, 2011, which totaled $1.69 billion and consisted of $332 million in borrowings under our revolving credit facility and $1.36 billion of outstanding senior notes.

Revolving Credit Facility. We, through RGS, have a $1.15 billion revolving credit facility, including availability for letters of credit of $200 million, that matures on June 15, 2014. As of December 31, 2012, RGS is allowed additional investments in Lone Star of up to $550 million, in ELG of up to $250 million, and in Ranch JV of up to $50 million. We are allowed to make additional investments in HPC up to $250 million less our ownership portion of indebtedness residing at HPC. In addition, the agreement allows for an additional investment in any joint venture of up to $250 million.

Borrowings under our revolving credit facility are secured by substantially all of our assets and are guaranteed by us and our subsidiaries. The revolving credit facility and the guarantees are senior to the Partnership’s and the other guarantor’s unsecured obligations.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternative base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 1.50% to 2.25% for base rate loans, 2.50% to 3.25% for Eurodollar loans.

We pay (i) a commitment fee ranging from 0.375% to 0.50% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 2.50% to 3.25% per annum of the average daily amount of such lender’s letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.125% per annum of the average daily amount of the letter of credit exposure.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.25, a consolidated EBITDA to consolidated interest expense ratio greater than 2.75, and a secured debt to consolidated EBITDA ratio less than 3. At December 31, 2012 and 2011, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the revolving credit facility);

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- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extensions thereof.

Senior Notes due 2016. In May 2009, we and Finance Corp. issued $250 million of senior notes that mature on June 1, 2016 (“2016 Notes”). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. The net proceeds were used to partially repay loans under our revolving credit facility. In May 2012, we redeemed 35%, or $88 million of the 2016 Notes, bringing the total outstanding balance to $162 million.

Beginning June 1 of the years indicated below, we may redeem all or part of these notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

June 1 of year ending:	Percentage of Redemption
2013	104.688%
2014	102.344%
2015 and thereafter	100.000%

At any time prior to June 1, 2013, we may also redeem all or part of the notes at a price equal to 100% of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at June 1, 2013 plus (ii) all required interest payments due on the note through June 1, 2013, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Senior Notes due 2018. In October 2010, we and Finance Corp. issued $600 million of senior notes that mature on December 1, 2018 (“2018 Notes”). The 2018 Notes bear interest at 6.875% paid semi-annually in arrears on June 1 and December 1, commencing June 1, 2011. The proceeds were used to redeem the senior notes due 2013 and to partially repay outstanding borrowings under the revolving credit facility.

At any time before December 1, 2013, up to 35% of the 2018 Notes can be redeemed at a price of 106.875% of the principal amount plus accrued interest. Beginning December 1 of the years indicated below, we may redeem all or part of these notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

December 1 of year ending:	Percentage of Redemption
2014	103.438%
2015	101.719%
2016 and thereafter	100.000%

At any time prior to December 1, 2014, we may also redeem all or part of the notes at a price equal to 100% of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at December 1, 2014 plus (ii) all required interest payments due on the note through December 1, 2014, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Senior Notes due 2021. In May 2011, we and Finance Corp. issued $500 million of senior notes that mature on July 15, 2021 (“2021 Notes”). The 2021 Notes bear interest at 6.5% paid semi-annually in arrears on January 15 and July 15, commencing on January 15, 2012. The proceeds were used to pay down the balance on our revolving credit facility.

At any time prior to July 15, 2014, we may redeem up to 35% of the 2021 Notes at a price equal to 106.5% of the principal amount plus accrued interest. Beginning on July 15 of the years indicated below, we may redeem all or part of the 2021 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

July 15 of year ending:	Percentage of Redemption
2016	103.250%
2017	102.167%
2018	101.083%

2019 and thereafter	100.000%

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At any time prior to July 15, 2016, we may also redeem all or part of the notes at a price equal to 100% of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at July 15, 2016 plus (ii) all required interest payments due on the note through July 15, 2016, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Senior Notes due 2023. In October 2012, we and Finance Corp. issued $700 million of senior notes that mature on April 15, 2023 ("2023 Notes"). The 2023 Notes bear interest at 5.5% paid semi-annually in arrears on April 15 and October 15, commencing on April 15, 2013. The proceeds were used to pay down the balance on our revolving credit facility.

At any time prior to October 15, 2015, we may redeem up to 35% of the 2023 Notes at a price equal to 105.5% of the principal amount plus accrued interest. Beginning on October 15 of the years indicated below, we may redeem all or part of the 2023 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

July 15 of year ending:	Percentage of Redemption
2017	102.750%
2018	101.833%
2019	100.917%
2020 and thereafter	100.000%

At any time prior to October 15, 2017, we may also redeem all or part of the notes at a price equal to 100% of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at October 15, 2017 plus (ii) all required interest payments due on the note through October 15, 2017, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Upon a change of control, as defined in the indenture, followed by a rating decline within 90 days, each holder of the 2016 Notes, 2018 Notes, 2021 Notes and the 2023 Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% of the principal amount plus accrued interest and liquidated damages, if any. Our ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including our revolving credit facility. Subsequent to the ETE Acquisition, in 2010, no noteholder exercised this option.

The 2016 Notes, 2018 Notes, 2021 Notes and 2023 Notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the 2016 Notes, 2018 Notes, 2021 Notes or 2023 Notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants. At December 31, 2012, we were in compliance with these covenants.

All of the 2016 Notes, 2018 Notes, 2012 Notes and 2023 Notes are jointly and severally guaranteed by all of our consolidated subsidiaries, other than Finance Corp. and a minor subsidiary. The senior notes and the guarantees are unsecured and rank equally with all of our and the guarantors' existing and future unsecured obligations. The senior notes and the guarantees will be senior in right of payment to any of our and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to our and the guarantors' secured obligations, including our revolving credit facility, to the extent of the value of the assets securing such obligations.

Equity Offerings. In March 2012, we issued 12,650,000 common units representing limited partner interests in a public offering at a price of $24.47 per common unit, resulting in net proceeds of $297 million. In May 2012, we used the net proceeds from this

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offering to redeem 35% of our outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under the revolving credit facility.

In October 2011, we sold 11,500,000 common units in an underwritten public offering, and received $232 million in proceeds. In May 2011, we issued 8,500,001 common units representing limited partnership interests resulting in net proceeds of $204 million, to partially fund our capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

Equity Distribution Agreement. In June 2012, we entered into an Equity Distribution Agreement with Citi under which we may offer and sell common units, representing limited partner interests, having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for us. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by us and Citi. We may also sell common units to Citi as principal for our own account at a price agreed upon at the time of sale. Any sale of common units to Citi as principal would be pursuant to the terms of a separate agreement between us and Citi. We intend to use the net proceeds from the sale of these units for general partnership purposes. As of December 31, 2012, we have issued 691,129 common units resulting in net proceeds of $15 million.

Contractual Obligations. The following table summarizes our total contractual cash obligations as of December 31, 2012:

	Payments Due By Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (including interest) (1)	$3,158	$137	$443	$395	$2,183
Operating leases	8	2	2	2	2
Purchase obligations (2)	122	122	—	—	—
Distributions and redemption of Series A Preferred Units (3)	244	8	16	16	204
Related party cash obligations (4)	24	10	14	—	—
Capital contribution commitments to unconsolidated affiliate (5)	1	1	—	—	—
Total (6)	$3,557	$280	$475	$413	$2,389

(1) Assumes a constant LIBOR interest rate of 0.843% plus applicable margin (2.50% as of December 31, 2012) for our revolving credit facility. The principal of our outstanding senior notes ($1.96 billion) bears a weighted average fixed rate of 6.5%.

(2) Excludes physical and financial purchases of natural gas, NGLs, and other commodities due to the nature of both the price and volume components of such purchases, which vary on a daily and monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

(3) Assumes that the Series A Preferred Units are redeemed for cash on September 2, 2029, and an annual distribution of $8 million.

(4) Includes the $10 million annual service fee paid to ETE under the services agreement between us and ETE, which expires in May 2015.

(5) Includes committed capital contributions to Ranch JV.

(6) Excludes deferred tax liabilities of $5 million as the amount payable by period cannot be readily estimated in light of net operating loss carryforwards and future business plans for the entity that generated the deferred tax liability.

OTHER MATTERS

Legal. We are involved in various claims, proceedings, lawsuits and audits by taxing authorities incidental to our business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on our business, financial condition, results of operations or cash flows.

Environmental Matters. For information regarding environmental matters, please read "Item 1. Business-Regulation-Environmental Matters."

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IRS Audits. The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. We have filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, we do not know whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The IRS is also conducting an audit of the 2007 through 2009 tax returns of one of our wholly owned subsidiaries and has proposed certain adjustments. The subsidiary has filed a protest with the IRS.

The statute of limitations for each of these audits has been extended to December 31, 2013. We, through our tax matters partner (our General Partner) and our tax advisers, will cooperate with the IRS examiners auditing these returns. Unitholders should consult their tax advisers if they have any questions.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could be different from those estimates.

The critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations are as follows:

Revenue and Cost of Sales Recognition. We record revenue and cost of gas and NGLs on the gross basis for those transactions where we act as the principal and take title to gas that we purchase for resale. When our customers pay us a fee for providing a service such as gathering or transportation we record the fees separately in revenues. We estimate certain revenue and expenses since actual amounts are not confirmed until after the financial closing process due to the standard settlement dates in the gas industry. We calculate estimated revenues using actual pricing and measured volumes. In the subsequent production month, we reverse the accrual and record the actual results. Prior to the settlement date, we record actual operating data to the extent available, such as actual operating and maintenance and other expenses. We do not expect actual results to differ materially from our estimates.

Purchase Method of Accounting. We make various assumptions in developing models for determining the fair values of assets and liabilities associated with business acquisitions. These fair value models, developed with the assistance of outside consultants, apply discounted cash flow approaches to expected future operating results, considering expected growth rates, development opportunities, and future pricing assumptions, to arrive at an economic value for the business acquired. We then determine the fair value of the tangible assets based on estimates of replacement costs less obsolescence. Identifiable intangible assets acquired consist primarily of customer relations and trade names. We value customer relations as the fair value of avoided customer churn costs compared to industry norms. We value trade names using the avoided royalty payment approach. We determine the value of liabilities assumed based on their expected future cash outflows. We record goodwill as the excess of the purchase price of each business unit over the sum of amounts allocated to the tangible assets and separately recognized intangible assets acquired, less liabilities assumed by the business unit.

Goodwill. We review the carrying value of goodwill on an annual basis or on an as needed basis, for indicators of impairment at each reporting unit that has recorded goodwill. We determine our reporting units based on identifiable cash flows of a reporting unit and how reporting unit managers evaluate the results of operations of the entity. Impairment is indicated whenever the carrying value of a reporting unit exceeds the estimated fair value of a reporting unit. We first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. For purposes of evaluating impairment of goodwill, we estimate the fair value of a reporting unit based upon future net discounted cash flows. In calculating these estimates, historical operating results and anticipated future economic factors, such as estimated volumes and demand for services, commodity prices, and operating costs are considered as a component of the calculation of future discounted cash flows. Further, the discount rate requires estimates of the cost of equity and debt financing. The estimates of fair value of these reporting units could change if actual volumes, prices, costs or discount rates vary from these estimates.

Equity Method Investments. The equity method of accounting is used to account for our interest in investments of greater than 20% voting stock or where we exert significant influence over an investee and lack control over the investee.

Depreciation Expense, Cost Capitalization and Impairment. Our assets consist primarily of natural gas gathering pipelines, processing plants, transmission pipelines, treating equipment, and natural gas compression equipment. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering costs and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed asset through the recording of depreciation

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expense. We capitalize the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

We generally compute depreciation using the straight-line method over the estimated useful life of the assets. Certain assets such as land, NGL line pack and natural gas line pack are non-depreciable. The computation of depreciation expense requires judgments regarding the estimated useful lives and salvage value of assets. As circumstances warrant, we review depreciation estimates to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the related carrying amounts may not be recoverable. Determining whether an impairment has occurred typically requires various estimates and assumptions, including determining which undiscounted cash flows are directly related to the potentially impaired asset, the useful life over which cash flows will occur, their amount, and the asset's residual value, if any. In turn, measurement of an impairment loss requires a determination of fair value, which is based on the best information available. We derive the required undiscounted cash flow estimates from our historical experience and our internal business plans. To determine fair value, we use our internal cash flow estimates discounted at an appropriate interest rate, quoted market prices when available and independent appraisals, as appropriate.

Equity Based Compensation. Restricted units are valued at the grant date closing price of the Partnership's common units. Phantom units are issued as either service condition awards (also defined as "time-based awards" in the LTIP plan) or market condition awards (also defined as "performance-based awards" in the LTIP plan). For service condition awards, the grant date fair value equals the grant date closing price of the Partnership's common units. For the market condition awards, we performed a Monte Carlo simulation that incorporated variables such as unit price volatility, merger and acquisition activity within the peer group, changes in credit ratings of the peer group members, and employee turnover. The grant date closing price of the Partnership's common units is also a factor in determining the grant-date fair value of the market condition awards.

Fair Value Measurements. Financial assets and liabilities, goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations are valued using a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1- unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2- inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3- inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

Our financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate and commodity derivative contracts and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate , commodity swaps and ethane put options are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Derivatives related to the Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, distribution yield and expected volatility, and are classified as Level 3 in the hierarchy.

RECENT ACCOUNTING PRONOUNCEMENTS

See discussion of new accounting pronouncements in Note 2 in the Notes to the Consolidated Financial Statements.

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Item 7A. Quantitative and Qualitative Disclosure about Market Risk

Risk and Accounting Policies. We are exposed to market risks associated with commodity prices, counterparty credit, and interest rates. Our management and the board of directors of our General Partner have established comprehensive risk management policies and procedures to monitor and manage these market risks. Our General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of our General Partner is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities.

Commodity Price Risk. We are a net seller of NGLs, condensate and natural gas as a result of our gathering and processing operations. The prices of these commodities are impacted by changes in supply and demand as well as market forces. Our profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect our ability to make distributions to our unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, we may not be able to match pricing terms or to cover our risk to price exposure with financial hedges, and we may be exposed to commodity price risk. Speculative positions are prohibited under our risk management policy.

We have swap contracts that settle against NGLs (propane, butane, and natural gasoline), condensate and natural gas market prices.

The following table sets forth certain information regarding our hedges outstanding at December 31, 2012. The relevant index price that we pay for NGLs is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas, as reported by the Oil Price Information Service (OPIS). The relevant index price for natural gas is NYMEX on the pricing dates as defined by the swap contracts. The relevant index for WTI is the monthly average of the daily price of WTI as reported by the NYMEX.

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive Weighted Average Price		Fair Value Asset/(Liability)	Effect of Hypothetical Change in Index*
							(in millions)	
January 2013-December 2013	Propane	79	(MBbls)	Index	1.03	($/gallon)	1	1
January 2013-December 2014	Normal Butane	236	(MBbls)	Index	1.62	($/gallon)	—	2
January 2013-March 2013	Natural Gasoline	7	(MBbls)	Index	2.27	($/gallon)	—	—
January 2013-December 2014	West Texas Intermediate Crude	356	(MBbls)	Index	99.47	($/Bbl)	2	3
January 2013-December 2014	Natural Gas	8,395,000	(MMBtu)	Index	3.87	($/MMBtu)	1	3
					Total Fair Value		$4	

* Price risk sensitivities were calculated assuming a theoretical 10% change in prices regardless of term or historical relationships between the contractual price of the instrument and the underlying commodity price. Interest rate sensitivity assumes a 100 basis point increase or decrease in the LIBOR yield curve. The price sensitivity results are presented in absolute terms.

Credit Risk. Our business operations expose us to credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to our overall profitability. We attempt to ensure that we issue credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or a parent company guarantee.

Item 8. Financial Statements and Supplementary Data

The financial statements set forth starting on page F-1 of this report are incorporated by reference.

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

None.

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Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such are defined in Rule 13a-15(e) of the Exchange Act). Based on management’s evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in achieving that level of reasonable assurance as of December 31, 2012.

Internal Control over Financial Reporting.

(a) Management’s Report on Internal Control over Financial Reporting. Management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for the Partnership as defined in Rules 13a-15(f) as promulgated under the Exchange Act.

Management of our General Partner assessed the effectiveness of our internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The evaluation included an evaluation of the design of our internal control over financial reporting and testing of the operating effectiveness of those controls.

Based on its assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2012.

(b) Audit Report of the Registered Public Accounting Firm. Grant Thornton LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this report, has issued an audit report on the Partnership’s internal control over financial reporting, which report is included herein on page F-3.

(c) Changes in Internal Control over Financial Reporting. As required by Exchange Act Rule 13a-15(f), management of our General Partner, including the Chief Executive Officer and Chief Financial Officer, also conducted an evaluation of our internal control over financial reporting to determine whether any change occurred during the last fiscal quarter of the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there has been no change in our internal control over financial reporting during the last fiscal quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management. Our General Partner manages and directs all of our operations and activities, including the appointment of up to 12 persons to serve on the Board of Directors. Our officers and directors are officers and directors of our General Partner. Our General Partner and its board members are not elected by our unitholders and are not subject to re-election on a regular basis in the future.

Corporate Governance. Our General Partner does not have a formal diversity policy or set of guidelines for selecting and appointing directors who comprise the Board of Directors. The Board of Directors has established a Nominating Committee to assist the Board and the member of our General Partner in identifying and recommending to the Board of Directors individuals qualified to become Board members. The full Board of Directors elects the directors. In considering whether to recommend any candidate for consideration by the full Board, the Nominating Committee will apply the criteria set forth in the Corporate Governance Guidelines to assess candidates. The Corporate Governance Guidelines include the following as part of that assessment: an individual’s background, ability, judgment, diversity, age, skill, experience in the context of the needs of the Board and whether the individual would qualify as an independent director under the independence rules of NYSE. The Nominating Committee seeks candidates with a broad diversity of experience, professions, skills and backgrounds. The Nominating Committee does not assign specific weights to particular criteria and no particular criterion is necessarily applicable to all prospective candidates. Directors are expected to exemplify the highest standards of personal and professional integrity and to constructively challenge management through their active participation and questioning. In particular, the Nominating Committee seeks directors with established strong professional reputations and expertise in areas relevant to the strategy and operation of the Partnership's business. Our General Partner believes that the backgrounds and qualifications of the directors, considered as a group, should provide a significant composite mix of experience, knowledge and abilities that will allow the Board to fulfill its duties and responsibilities.

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Our Board of Directors currently consists of five members, three of whom qualify as independent under NYSE standards for audit committee members and one person who is a member of our executive management. Mr. John D. Harkey, Jr., Mr. Rodney L. Gray and Mr. James W. Bryant are independent.

The Board of Directors has adopted Corporate Governance Guidelines to assist it in the exercise of its responsibilities to provide effective governance over our affairs for the benefit of our unitholders. In addition, we have adopted a Code of Business Conduct, which sets forth legal and ethical standards of conduct for all of our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our General Partner. The Corporate Governance Guidelines, the Code of Business Conduct, Code of Conduct for Senior Financial Officers, and the charters of our audit and risk, compensation and nominating committees are available on our website at www.regencygasservices.com. You may also contact our investor relations department at (214) 840-5477 for printed copies of these documents free of charge. Amendments to, or waivers from, the Code of Business Conduct will also be available on our website and reported as may be required under SEC rules; however, any technical, administrative or other non-substantive amendments to the Code of Business Conduct may not be posted. Note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found or provided at that Internet address or at our website in general is intended or deemed to be incorporated by reference herein.

Audit and Risk Committee. The Board of Directors has established an Audit and Risk Committee in accordance with Exchange Act rules. The Board of Directors appointed three directors, Rodney L. Gray, John D. Harkey, Jr. and James W. Bryant, who are independent under the NYSE's standards for audit committee members, to serve on its Audit and Risk Committee. In addition, the Board of Directors determined that at least one member, Rodney L. Gray, the chairman of the Audit and Risk Committee, has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407(d)(5) of Regulation S-K. Mr. Harkey currently serves as the Chairman of the Board of Directors. Mr. Harkey currently serves as a member or chairman of the audit committee of three other publicly traded companies, in addition to his service as a member of the Audit and Risk Committee. As required by Rule 303A.07 of the NYSE Listed Company Manual, the Board of Directors has determined that such simultaneous service does not impair Mr. Harkey's ability to effectively serve on our Audit and Risk Committee.

The Audit and Risk Committee meets on a regularly-scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit and Risk Committee has the authority and responsibility to review our external financial reporting, to review our procedures for internal auditing and the adequacy of our internal accounting controls, to consider the qualifications and independence of our independent accountants, to engage and resolve disputes with our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work that may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit and Risk Committee deems advisable. The Audit and Risk Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by SAS 114 (Communications with Audit and Risk Committees), and makes recommendations to the Board of Directors for inclusion in our audited financial statements on this Form 10-K.

The Audit and Risk Committee is authorized to recommend to the Board of Directors any changes or modifications to its charter that the Audit and Risk Committee believes may be required.

The Board's Role in Risk Oversight. The Board of Directors performs oversight functions to protect our unitholders' and other stakeholders' interest in the long-term health and the overall success of the Partnership and its financial strength. The full Board of Directors is actively involved in overseeing risk management for the Partnership. It does so in part through discussion and review of our business, financial and corporate governance practices and procedures. The Board's Audit and Risk Committee identifies and reviews the risks confronted by the Partnership with respect to its operations and financial condition, establishes limits of risk tolerance with respect to the Partnership's hedging activities and exposure to customers' credit risk and ensures adequate property and liability insurance coverage.

In addition, each of our other Board committees considers the risks within its areas of responsibilities. For example, the Audit and Risk Committee reviews risks related to financial reporting. The Audit and Risk Committee discusses policies with respect to risk assessment and risk management, reviews contingent liabilities and risks that may be material to the Partnership and assesses major legislative and regulatory developments that could materially impact the Partnership's contingent liabilities and risks. The Audit and Risk Committee is required to discuss any material violations of our policies brought to its attention on an ad hoc basis. Additionally, the outcome of the audit risk assessment is presented to the Audit and Risk Committee annually; this assessment identifies internal control risks and drives the internal audit plan for the coming year. Material violations of our Code of Business Conduct and related corporate policies are reported to the Audit and Risk Committee and, as required, are reported to the full

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Board. The Compensation Committee reviews our overall compensation program and its effectiveness at both linking executive pay to performance and aligning the interests of our executives and our unitholders.

Meetings of Non-Management Directors and Communication with Directors. Our non-management directors are required by NYSE rules to meet regularly in executive session. In practice, they meet in executive session at most meetings of the Board. The presiding director at these executive sessions is rotated among the independent directors, John D. Harkey, Jr., Rodney L. Gray and James W. Bryant.

Unitholders and interested parties may communicate with the independent directors directly and anonymously by writing to the Chairman of the Audit and Risk Committee, Regency GP LLC, 2001 Bryan Street, Suite 3700, Dallas, Texas 75201.

Directors and Executive Officers of the General Partner. The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of March 1, 2013. Executive officers and directors are elected for indefinite terms.

Name	Age	Position with Regency GP LLC
Michael J. Bradley	58	Director, President and Chief Executive Officer
Thomas E. Long	56	Executive Vice President and Chief Financial Officer
Jim Holotik	60	Executive Vice President, Chief Commercial Officer
A. Troy Sturrock	42	Vice President, Controller and Principal Accounting Officer
John D. Harkey, Jr.	52	Chairman of the Board of Directors
John W. McReynolds	62	Director
Rodney L. Gray	61	Director
James W. Bryant	79	Director

Michael J. Bradley was elected to the Board of Directors of Regency GP LLC in January 2008. In November 2010, he was also elected president and CEO of Regency. Prior to joining Regency, he served as President, Chief Executive Officer and a director of Matrix Service Company since November 2006. Prior to joining Matrix Service Company, Mr. Bradley served as President and CEO of DCP Midstream Partners and was a member of the board of its general partner. Mr. Bradley was named Group Vice President of Gathering and Processing for Duke Energy Field Services (DEFS) in 2004 and served as Executive Vice President (DEFS) from 2002 to 2004. From 1994 to 2002, he served as Senior Vice President (DEFS) and was responsible for business development and commercial activities. Mr. Bradley graduated from the University of Kansas with a bachelor’s degree in civil engineering. He also completed the Duke University Executive Management Program. Mr. Bradley is a member of the American Society of Civil Engineers. He also serves on the advisory board for the University of Kansas, School of Engineering.

Thomas E. Long was elected executive vice president and chief financial officer of Regency GP LLC in November 2010. From May 2008 to November 2010, Mr. Long served as vice president and chief financial officer of Matrix Service Company. Prior to joining Matrix, he served as vice president and chief financial officer of DCP Midstream Partners, LP, a publicly traded natural gas and natural gas liquids midstream business company located in Denver, CO. In that position, he was responsible for all financial aspects of the company since its formation in December 2005. From 1998 to 2005, Mr. Long served in several executive positions with subsidiaries of Duke Energy Corp., one of the nation’s largest electric power companies. During his tenure at Duke Energy, Mr. Long served as vice president and chief financial officer of its publicly owned power company in Ecuador; vice president and treasurer of Duke Energy Field Services, Denver; and executive vice president of National Methanol Company, a Duke Energy Corp. chemical joint-venture in Saudi Arabia. Starting in 1991, Mr. Long held financial management positions at PanEnergy Corp., Houston. He began his career in 1979 at Texas Eastern Corp., Houston. As a Certified Public Accountant, Mr. Long has a Bachelor of Arts in Accounting from Lamar University, Beaumont, TX.

Jim Holotik was elected executive vice president and chief commercial officer of Regency GP LLC in October 2010. From 2004 to October 2010, Mr. Holotik served in various positions at ETP, most recently serving as president of Transwestern Pipeline Company, LLC and leading the mergers and acquisition efforts for Energy Transfer. Mr. Holotik began his career in 1976 in exploration and moved to the natural gas industry in 1986 when he joined Endevco Oil and Gas. He later held positions as executive vice president of Cornerstone Natural Gas and was director of the East and West regions for El Paso Field Services. He joined Energy Transfer in 2004 as commercial vice president of project development, and later became president of Transwestern following its acquisition by Energy Transfer. Mr. Holotik has a bachelor's degree in business administration from Stephen F. Austin University.

A. Troy Sturrock was elected vice president and controller of Regency GP LLC in February 2008, and in November 2010 was appointed as the principal accounting officer. From June 2006 to February 2008, Mr. Sturrock served as the assistant controller and director of financial reporting and tax for Regency GP LLC. From January 2004 to June 2006, Mr. Sturrock was associated

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with the Public Company Accounting Oversight Board, where he was an inspection specialist in the division of registration and inspections. Mr. Sturrock served in various roles at PricewaterhouseCoopers LLP from 1995 to 2004, most recently as a senior manager in the audit practice specializing in the transportation and energy industries. Mr. Sturrock is a Certified Public Accountant.

John D. Harkey, Jr. was elected Chairman of the Board of Directors of Regency GP LLC in May 2010. Mr. Harkey has served as Chief Executive Officer and Chairman of Consolidated Restaurant Companies, Inc., since 1998. Mr. Harkey currently serves on the Board of Directors of Leap Wireless International, Inc., Loral Space & Communications, Inc., Emisphere Technologies, Inc., and the Board of Directors for the Baylor Health Care System Foundation. He currently serves on the Audit Committees of Loral and Emisphere. He also serves on the President's Development Council of Howard Payne University and on the Executive Board of Circle Ten Council of the Boy Scouts of America. In May 2006, Mr. Harkey was elected as a director of ETE's General Partner and member of their Audit Committee. He currently serves as the Chairman of the Audit Committee of ETE's General Partner. Among the reasons for Mr. Harkey's appointment as a director is his background in corporate finance as well as his experience as a director on the boards and audit committees of several other public companies.

John W. McReynolds was elected to the Board of Directors of Regency GP LLC in May 2010. Mr. McReynolds is a Director and the President and Chief Financial Officer of Energy Transfer Equity. Mr. McReynolds has served as the President of ETE since March 2005 and as a Director and the Chief Financial Officer of ETE since August 2005. He has previously served as a director of Energy Transfer Partners from August 2001 through May 2010. Prior to becoming President of ETE, Mr. McReynolds was a partner with the international law firm of Hunton & Williams LLP for over 20 years. As a lawyer, he specialized in energy related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in numerous arbitration, litigation, and governmental proceedings, including as an expert in special projects for Boards of Directors of public companies. Mr. McReynolds has served as a Director of ETE's General Partner since August 2004. Among the reasons for Mr. McReynolds' appointment as a director are his legal background and his extensive experience in energy-related corporate finance. Mr. McReynolds has relationships with executives and senior management at several companies in the energy sector, as well as with investment bankers who cover the industry.

Rodney L. Gray was elected to the Board of Directors of Regency GP LLC on February 22, 2008. From June 2009 to June 2010, Mr. Gray served as Chief Financial Officer and Executive Vice President of Cobalt International Energy, Inc. From 2003 to April 2009, Mr. Gray served as chief financial officer of Colonial Pipeline, an interstate carrier of petroleum products. Mr. Gray currently serves on the Board of Directors of Rose Rock Midstream GP, LLC, the general partner of Rose Rock Midstream, L.P. Mr. Gray received a Bachelor of Science degree in Accounting from the University of Wyoming and a Bachelor of Science degree in Mathematics and Economics from Rock Mountain College in Billings, Montana. Among the reasons for Mr. Gray's appointment as a director are his more than 30 years of experience in the energy industry, his past experiences as an executive with financial leadership responsibility at energy companies, and his current position as a member of the board of directors of another master limited partnership.

James W. Bryant was elected to the Board of Directors of Regency GP LLC in July 2010. Mr. Bryant is a chemical engineer and has more than 40 years of experience in all phases of the natural gas business, specifically in the engineering and management of midstream facilities. Mr. Bryant currently serves as a partner and member of the Board of Directors for Cardinal Midstream, LLC. Prior to that, he was a co-founder of Cardinal Gas Solutions LP, a contract gas treating company that was later sold to Crosstex Energy Services, L.P. In 2003, Mr. Bryant co-founded Regency Gas Services, LLC, the predecessor to Regency, and served as president of Regency Gas Services, LLC, until December 2004, when it was sold to Hicks, Muse, Tate & Furst Inc. He has been instrumental in the formation, development and growth of numerous other companies in the midstream sector, including those specializing in natural gas treating. Mr. Bryant has previously served on the Board of Directors for Gulf Energy & Development, Endevco, Inc., Oachita Energy Company, and Regency Gas Services, LLC. Mr. Bryant received a bachelor's degree in chemical engineering from Louisiana Tech University. Among the reasons for Mr. Bryant's appointment as a director are his more than 40 years of experience in the midstream natural gas business as well as his experience as a director on the boards of several other public companies.

Reimbursement of Expenses of Our General Partner. 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. In addition, we are a party to a services agreement with Services Co., an affiliate of ETE, pursuant to which Services Co. provides certain general and administrative services to us and our partner. The reimbursement of expenses of our General Partner and its affiliates and our payments under the services agreement with Services Co. will reduce our cash available for debt service.

Section 16(a) Beneficial Ownership Reporting Compliance. Section 16(a) of the Exchange Act requires executive officers, directors and persons who beneficially own more than 10% of a security registered under Section 12 of the Exchange Act to file initial reports of ownership and reports of changes of ownership of such security with the SEC. Copies of such reports are required to be furnished to the issuer. The common units of the Partnership were first registered under Section 12 of the Exchange Act on

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January 30, 2006. Based solely on a review of reports furnished to our General Partner, or written representations from reporting persons that all reportable transactions were reported, we believe that, during the fiscal year ended December 31, 2012, our General Partner's executive officers, directors and greater than 10% common unitholders filed all reports they were required to file under Section 16(a).

Item 11. Executive Compensation

Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Instead, as a limited partnership, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of our management functions. As a result, the executive officers of our General Partner are essentially our executive officers, and their compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of our General Partner as set forth below. The executive officers we refer to in this discussion as our "named executive officers" are the following officers of our General Partner:

- Michael J. Bradley, President and Chief Executive Officer;
- Thomas E. Long, Executive Vice President and Chief Financial Officer;
- Jim Holotik, Executive Vice President and Chief Commercial Officer;
- A. Troy Sturrock, Vice President, Controller and Principal Accounting Officer; and
- Paul M. Jolas, former Executive Vice President, Chief Legal Officer and Secretary.

Mr. Jolas resigned, effective May 16, 2012, from his position.

Our General Partner's Philosophy for Compensation of Executives

In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based and that executives' base salary levels should be competitive in the marketplace for executive talent and abilities. Our General Partner also believes the incentives should be competitive in the marketplace and balanced between short and long-term performance. Our General Partner believes this balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of the Partnership's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of our named executive officers to the success of the Partnership and (ii) the annual grant of phantom units under our equity incentive plans, which are intended to provide a longer term incentive to our key employees to focus their efforts on increasing the market price of our publicly traded units and to increase the cash distribution we pay to our unitholders. We refer to these awards as "phantom units," consistent with the use of such term in our long-term incentive plans. Our General Partner believes that these equity-based incentive arrangements are important in attracting and retaining our executive officers and key employees as well as motivating these individuals to achieve our business objectives. The equity-based compensation also reflects the importance we place on aligning the interests of our named executive officers with those of our unitholders.

Beginning in December 2012, we began equity-based unit awards in the form of phantom units that vest, based upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year. Prior to December 2012, our equity-based awards were primarily in the form of phantom units that vest over a specified time period, with substantially all of these awards vesting over a five-year period at 20% per year based on continued employment through each specified vesting date.

While we are responsible for the direct payment of the compensation of our named executive officers as employees of the Partnership, the Partnership does not participate or have any input in any decisions as to the compensation policies of our General Partner or the compensation levels of the executive officers of our General Partner. The compensation committee of the board of directors of our General Partner (the "Compensation Committee") is responsible for the approval of the compensation policies and the compensation levels of these executive officers. We directly pay these executive officers in lieu of receiving an allocation of overhead related to executive compensation from our General Partner. For the year ended December 31, 2012, we paid 100% of the compensation of the executive officers of our General Partner as we represent the only business currently managed by our General Partner.

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Our General Partner is ultimately controlled by the general partner of ETE. We pay quarterly distributions to our General Partner in accordance with our partnership agreement with respect to its ownership of a general partner interest and the incentive distribution rights specified in our partnership agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our partnership agreement. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner's executive officers. Our General Partner's incentive distribution rights are described in detail in "Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities." Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

For a more detailed description of the compensation of our named executive officers, please see "—Compensation Tables" below.

Compensation Committee

We are a limited partnership and our units are listed on the NYSE. Although the rules of the NYSE do not require publicly traded limited partnerships to have a compensation committee, the board of directors of our General Partner has established a Compensation Committee that is composed of two directors of our General Partner (Messrs. Harkey and Gray) who our General Partner has determined to be "independent" (as that term is defined in the applicable NYSE corporate governance standards) and one director (Mr. McReynolds) who is not "independent" under the NYSE standards.

The Compensation Committee is directly responsible for establishing annual and long-term performance goals and objectives for our elected officers. The responsibilities of the Compensation Committee are:

- to set the compensation of the Chief Executive Officer and the other elected officers based upon the evaluation of the performance of the Chief Executive Officer and other elected officers;
- to evaluate the performance of the Chief Executive Officer and other elected officers in light of the approved performance goals and objectives;
- to make awards under existing cash-based and equity-based compensation plans and to make recommendations to the Board with respect to new cash-based incentive compensation plans and equity-based compensation plans; and
- to prepare an annual performance self-evaluation of the Compensation Committee.

In addition, the Compensation Committee:

- administers the Partnership's incentive plans;
- determines and certifies the shares awarded under corporate performance-based plans; and
- advises on the setting of compensation for senior executives whose compensation is not otherwise set by the Compensation Committee.

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2012, the compensation paid to our named executive officers consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- equity-based awards granted under our long-term incentive plans; and

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- qualified retirement plan benefits.

Methodology

The Compensation Committee considers relevant data available to it to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers. The Compensation Committee also considers individual performance, levels of responsibility, skills and experience. Periodically, the Compensation Committee engages a third-party consultant to provide market information for compensation levels at peer companies in order to assist the Compensation Committee in its determination of compensation levels for our executive officers. Most recently, the Compensation Committee engaged BDO Seidman, LLP ("BDO") during the year ended December 31, 2010 to assist in the determination of compensation levels for our senior management. The results of this study were utilized to determine long-term incentive awards and bonuses during 2010, 2011, and 2012. The consultant provided an analysis of compensation for senior executives at the following 20 companies in the energy industry, comprised primarily of midstream and exploration and production companies:

- Atlas Pipeline Partners, L.P. Holly Energy Partners, L.P.
- Boardwalk Pipeline Partners, LP Magellan Midstream Partners, L.P.
- Buckeye Partners, L.P. MarkWest Energy Partners, L.P.
- Copano Energy, L.L.C. Martin Midstream Partners L.P.
- Crosstex Energy L.P. Nustar Energy L.P.
- DCP Midstream Partners, LP Plains All American Pipeline, L.P.
- Eagle Rock Energy Partners, L.P. Quicksilver Gas Services LP
- Energy Transfer Partners, L.P. Sunoco Logistics Partners L.P.
- Enterprise Products Partners L.P. Targa Resources Partners LP
- Hiland Partners, LP Teppco Partners, L.P.

The compensation analysis provided by BDO covered annual salary, annual cash bonus and long-term incentive arrangements for the senior executives of these companies. The Compensation Committee utilized the information provided by BDO to compare the levels of base salary, annual bonus and long-term equity incentives at these other companies with those of our named executive officers to ensure that compensation of our named executive officers is competitive with the compensation for executive officers of these other companies. The Compensation Committee did not attempt to benchmark the base salary, annual bonus or long-term equity incentives to any percentage of, or numerical average of, the compensation levels at these other companies. BDO did not provide any services during 2012 and 2011 and also did not provide any non-executive compensation services for the Partnership during 2010.

In addition to the periodic engagement of a third-party consultant, the Compensation Committee also utilizes information obtained from other sources, such as third-party surveys, for comparison purposes in its determination of compensation levels for our executive officers.

Annual Base Salary. The base salaries of our named executive officers are determined by the Compensation Committee after taking into account the recommendations of our CEO. For 2012, the Compensation Committee approved an increase of 3% to Mr. Bradley's annual base salary, 4% to Mr. Long's annual base salary, 3% to Mr. Holotik's annual base salary, and 3% to Mr. Sturrock's annual base salary. The Compensation Committee determined that such increases in annual base salary were warranted in light of the individual performance and levels of responsibility related to management of the Partnership and its subsidiaries. For 2011, the Compensation Committee did not approve increases for our named executive officers, primarily due to increases that had been granted in 2010 and the commencement of employment in late 2010 or early 2011 by three named executive officers.

Annual Cash Bonus. In addition to base salary, the Compensation Committee makes a determination whether to award our named executive officers discretionary annual cash bonuses following the end of the year. These discretionary bonuses, if awarded, are intended to reward our named executive officers for the achievement of financial performance objectives during the year for which the bonuses are awarded in light of the contribution of each individual to our profitability and success during such year. In this regard, the Compensation Committee takes into account whether the Partnership achieved or exceeded its internal EBITDA budget for the year. The Compensation Committee also considers the recommendation of our CEO in determining the specific annual cash bonus amounts for each of the other named executive officers. Beginning in 2011, the Compensation Committee did not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses,

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and the Compensation Committee does not utilize any formulaic approach to determine annual bonuses. Prior to 2011, as discussed further below, annual bonus payments were based on certain performance measures, and the Compensation Committee had a designated level of discretion with respect to such bonus payments. The goal of the Compensation Committee in changing the annual bonus methodology in 2011 was to conform to the bonus programs of ETE.

The Partnership's internal financial budgets are generally developed for each business segment, and then aggregated with appropriate corporate level adjustments, to reflect an overall performance objective that is reasonable in light of market conditions and opportunities based on a high level of effort and dedication across all segments of the Partnership's business. The evaluation of the Partnership's performance versus its internal financial budget is based on the Partnership's EBITDA for a calendar year. In general, the Compensation Committee believes that Partnership performance at or above the internal EBITDA budget would support bonuses to our named executive officers ranging from 80% to 120% of their annual salary. The individual bonus amounts for each named executive officer also reflect the Compensation Committee's view of the impact of such individual's efforts and contributions towards (i) achievement of the Partnership's success in exceeding its internal financial budget, (ii) the development of new projects that are expected to result in increased cash flows from operations in future years and (iii) the overall management of the Partnership's business.

In February 2013, the Compensation Committee approved cash bonuses relating to the 2012 calendar year to Messrs. Bradley, Long, Sturrock and Holotik of $600,000, $305,000, $145,000 and $275,000, respectively. In approving the cash bonuses for Messrs. Bradley, Long, Sturrock and Holotik, the Compensation Committee took into account the achievement by the Partnership of approximately 97% of its internal EBITDA budget of $497 million for 2012. Accordingly, the approved amounts represent 99%, 98% and 95% of the bonus targets for Messrs. Long, Sturrock and Holotik, respectively. In addition to the performance of the Partnership in relation to its internal EBITDA budget during 2012, the Compensation Committee also took into account Mr. Bradley's role in managing the Partnership and positioning it for future growth.

Equity-Based Awards. Each of our long-term incentive plans authorizes the Compensation Committee, in its discretion, to grant awards of options to purchase our common units; awards of our restricted units, phantom units and common units; awards of distribution equivalent rights ("DERs"); awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of the Partnership and its affiliates and subsidiaries. The Compensation Committee approved the terms of the unit grants awarded to our named executive officers, including the number of Common Units subject to the unit award and the vesting structure of those unit awards.

Subsequent to ETE's acquisition of our General Partner in 2010, all of the new awards granted have provided for vesting over a specified time period, with vesting based on continued employment as of each applicable vesting date, rather than vesting based on the satisfaction of any performance objectives which is more generally prevalent with companies in the energy industry. In December 2012, the Compensation Committee approved grants of phantom unit awards to Messrs. Bradley, Long, Sturrock and Holotik of 50,000 units, 25,000 units, 9,200 units and 22,500 units, respectively. These phantom unit awards provide for vesting of 60% at the end of the third year and vesting of the remaining 40% at the end of the fifth year, subject to continued employment through each specified vesting date. These phantom unit awards entitle the recipients of the unit awards to receive, with respect to each Regency Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. In approving the grant of such unit awards, the Compensation Committee took into account the same factors as discussed above under the caption "Annual Cash Bonus," the long-term objective of retaining such individuals as key drivers of the Partnership's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity awards subject to vesting.

The issuance of Common Units pursuant to our equity incentive plans is intended to serve as a means of incentive compensation; therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

The unit awards under our equity incentive plans generally require the continued employment of the recipient during the vesting period. The Compensation Committee may, but is not required to, accelerate the vesting of unvested unit

awards in the event of the termination or retirement of an executive officer. The Compensation Committee did not accelerate the vesting of unit awards in 2012.
Prior to ETE's acquisition of our General Partner, we issued awards with different features than those that we currently issue. In May 2010, prior to the change of control, we granted phantom units for which 40% were subject to time-based vesting restrictions and 60% were subject to performance-based vesting restrictions. Time-based restrictions for those awards lapse as to one-third of any unit on each of the first three anniversaries of the date of grant. The units subject to performance-based vesting restrictions vest at the end of a three-year period based on our total unitholder return. The Compensation Committee elected to grant these phantom units to incentivize continued performance. Accordingly, the vesting provisions of these phantom unit awards did not accelerate when the change of control of our General Partner occurred shortly after the May 7, 2010 grant.

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Qualified Retirement Plan Benefits. We participate in our affiliates' 401(k) plan, which covers substantially all of our employees, including our named executive officers. The plan is subject to the provisions of ERISA. Employees who have completed one hour of service and have attained age 18 years of age (age 21 for certain union workers) are eligible to participate. Employees may elect to defer up to 100% of their eligible compensation after applicable taxes, as limited under the IRC. We are required to make a matching contribution that is not less than the aggregate amount of matching contributions that would be credited to a participant's account based on a rate of match equal to 100% of each participant's elective deferrals up to 5% of covered compensation. The entire amount credited to the participant's account is fully vested and non-forfeitable at all times. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement.

Beginning January 1, 2013, the Partnership will provide a 3% profit sharing contribution to employee 401(k) accounts for all employees with base compensation of $125,000 or less. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Health and Welfare Benefits. All full-time employees, including our named executive officers, may participate in our health and welfare benefit programs including medical, dental, vision, flexible spending, life insurance and disability insurance.

Termination Benefits. Our named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner. Our long-term incentive plans provide for immediate vesting of all unvested awards in the event of a change in control, as defined in our long-term incentive plans. No such accelerated vesting occurred in 2012.

Deferred Compensation Plan. Employees earning more than $125,000 per year have the option to participate in a deferred compensation plan ("DC Plan"). The DC Plan permits eligible highly compensated employees to defer a portion of their salary and/or bonus until retirement or termination of employment or other designated distribution. Under the DC Plan, each year eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested unit distribution income, and/or 50% of their discretionary performance bonus compensation to be earned for services performed during the following year. Pursuant to the DC Plan, we may make annual discretionary matching contributions to participants' accounts; however, we have not made any discretionary contributions to participants' accounts and currently have no plans to make any discretionary contributions to participants' accounts. All amounts credited under the DC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings (or losses) based on hypothetical investment fund choices made by the participants among available funds.

Participants may also elect to have their accounts distributed in one lump sum payment or in annual installments over a period of 3 or 5 years upon retirement, and in a lump sum upon other termination. Upon a change in control (as defined in the DC Plan), all DC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the DC Plan's normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement.

Risk Assessment Related to our Compensation Structure. We believe our compensation plans and programs for our named executive officers, as well as our other employees, are appropriately structured and are not reasonably likely to result in material risk to the Partnership. We believe our compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm our value or reward poor judgment. We also believe we have allocated our compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for the executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of an operating segment. We generally determine whether, and to what extent, our named executive officers receive a cash bonus based on our achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership's success. We use phantom units rather than unit options for equity awards because phantom units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options "in-the-money." Finally, the time-based vesting over five years for our long-term incentive awards ensures that our employees' interests align with those of our Unitholders for the long-term performance of the

Partnership.

Recoupment Policy

We currently do not have a recovery policy applicable to annual incentive bonuses or equity awards. The Compensation Committee will continue to evaluate the need to adopt such a policy.

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Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is not subject to the deduction limitations under section 162(m) of the IRC and therefore is generally fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation

For our unit-based compensation arrangements, including equity-based awards issued to certain of our named executive officers by an affiliate (as discussed above), we record compensation expense over the vesting period of the awards, as discussed further in Note 17 in the Notes to our Consolidated Financial Statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Harkey, McReynolds and Gray served on the Compensation Committee during 2012. During 2012, none of the members of the committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company’s board of directors. In addition, none of the members of the Compensation Committee are former employees of ours or any of our subsidiaries.

Report of Compensation Committee

The Compensation Committee of the board of directors of our General Partner has reviewed and discussed the section entitled “Compensation Discussion and Analysis” with the management of Regency Energy Partners LP. Based on this review and discussion, we have recommended to the board of directors of our General Partner that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

Compensation Committee

John D. Harkey, Jr., Chairman

John W. McReynolds

Rodney L. Gray

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this annual report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

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COMPENSATION TABLES AND NARRATIVES

Summary Compensation Table

Name and Principal Position	Year (#)(1)	Salary ($)	Bonus ($)(2)	Equity Awards ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)(4)	Total ($)(5)
Michael J. Bradley	2012	$592,250	$600,000	$1,054,000	$ —	$ 41,322	$2,287,572
President and Chief	2011	575,000	603,750	1,216,000	—	51,392	2,446,142
Executive Officer	2010	44,231	—	2,447,500	—	10,701	2,502,432
Thomas E. Long	2012	312,000	305,000	527,000	—	20,297	1,164,297
Executive Vice	2011	300,000	315,000	547,200	—	210,226	1,372,426
President and Chief Financial Officer	2010	15,000	—	965,750	—	11,630	992,380
A. Troy Sturrock	2012	187,975	145,000	193,936	—	12,562	539,473
Vice President,	2011	182,500	138,700	194,560	—	26,869	542,629
Controller and Principal Accounting Officer	2010	176,038	95,765	315,511	—	25,734	613,048
Jim Holotik	2012	293,550	275,000	474,300	—	13,322	1,056,172
Executive Vice President and Chief Commercial Officer	2011	285,000	270,750	547,200	—	13,441	1,116,391
Paul M. Jolas	2012	30,000	—	232,183	3,497	402,593	668,273
Former Executive Vice	2011	360,000	342,000	—	—	42,554	744,554
President, Chief Legal Officer and Secretary	2010	310,060	316,261	918,232	—	48,506	1,593,059

(1) The information provided in the Summary Compensation Table reflects full-year information for each individual for the years in which such individuals are considered Named Executive Officers except for Mr. Jolas who separated from the company on May 16, 2012. Mr. Holotik became a Named Executive Officer beginning in 2011; Messrs. Bradley, Long and Sturrock became Named Executive Officers beginning in 2010.

(2) The bonus amounts reflect discretionary cash bonuses for our named executive officers for 2012 approved by the Compensation Committee in February 2013, which are expected to be paid in March 2013.

(3) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718. See Note 17 in the Notes to the Consolidated Financial Statements for additional assumptions underlying the value of the equity awards. The amount reflected for Mr. Jolas for 2012 represents the fair value, computed in accordance with FASB ASC Topic 718, related to the accelerated vesting of 14,734 phantom units in connection with Mr. Jolas' severance agreement in 2012.

(4) The amounts reflected in "All Other Compensation" for 2012 include (i) housing allowances for Messrs. Bradley and Long in the amounts of $28,000 and $7,015, respectively, (ii) contributions to the 401(k) plan on behalf of each named executive officer in the amount of $12,250 each, (iii) a severance payment to Mr. Jolas of $390,000, and (iv) the dollar value of life insurance premiums paid for the benefit of the named executive officers. Vesting in 401(k) contributions occurs immediately.

(5) Amounts presented do not include the value of unvested phantom unit awards under long-term incentive plans that would fully vest upon a change of control as defined in our plans, which amounts are reflected in the "Outstanding Equity Awards at Year-End Table".

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Grant of Plan-Based Awards for the Year Ended December 31, 2012

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	All Other Unit Awards: Number of Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Unit Awards[1]
Michael J. Bradley	12/17/2012	—	—	—	50,000	—	—	$1,054,000
Thomas E. Long	12/17/2012	—	—	—	25,000	—	—	527,000
A. Troy Sturrock	12/17/2012	—	—	—	9,200	—	—	193,936
Jim Holotik	12/17/2012	—	—	—	22,500	—	—	474,300
Paul M. Jolas [2]	1/27/2012	—	—	—	14,734	—	—	232,183

(1) We have computed the grant date fair value of these phantom unit awards in accordance with FASB ASC Topic 718, as further described below and in Note 17 in the Notes to our Consolidated Financial Statements.

(2) The amount reflected for Mr. Jolas for 2012 represents the fair value, computed in accordance with FASB ASC Topic 718, related to the accelerated vesting of 14,734 phantom units in connection with Mr. Jolas' severance agreement in 2012.

Narrative Disclosure to Summary Compensation Table and Grants of the Plan-Based Awards Table

A description of material factors necessary to understand the information disclosed in the tables above with respect to salaries, bonuses, equity awards, nonqualified deferred compensation earnings, and 401(k) plan contributions can be found in the compensation discussion and analysis that precedes these tables.

Outstanding Equity Awards at December 31, 2012

Name	Unit Awards Grant Date	Number of Units that have not Vested [1] (#)	Market Value of Units That Have Not Vested [2] ($)	Equity Incentive Plan Awards: Number of Units That Have Not Vested [3] (#)	Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested [2] ($)
Michael J. Bradley	12/17/2012	50,000	$ 1,084,000	—	$ —
	12/21/2011	40,000	867,200	—	—
	12/17/2010	30,000	650,400	—	—
	11/21/2010	30,000	650,400	—	—
Thomas E. Long	12/17/2012	25,000	542,000	—	—
	12/21/2011	18,000	390,240	—	—
	12/17/2010	14,100	305,688	—	—
	12/1/2010	9,000	195,120	—	—
A. Troy Sturrock	12/17/2012	9,200	199,456	—	—
	12/21/2011	6,400	138,752	—	—
	12/17/2010	6,000	130,080	—	—
	5/7/2010	467	10,125	2,100	45,528
Jim Holotik	12/17/2012	22,500	487,800	—	—
	12/21/2011	18,000	390,240	—	—
	12/17/2010	14,100	305,688	—	—

(1) Phantom unit awards outstanding as of December 31, 2012 reflected in the table above vest (i) at a rate of 60% in 2015 and 40% in 2017 for awards granted in 2012 and (ii) ratably on each anniversary of the grant date through 2016 for awards granted in 2011 and through 2015 for awards granted in 2010.

(2) Market value was computed as the number of unvested awards as of December 31, 2012 multiplied by the closing price of our common units on December 31, 2012.

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(3) The forfeiture restrictions on these market-based phantom unit awards lapse on March 15, 2013 based upon the Partnership's achievement of certain levels of total unitholder return. The units subject to performance-based vesting restrictions vest at the end of a three-year period based on our total unitholder return.

Option Exercises and Stock Vested for the Year Ended December 31, 2012

Name	Unit Awards Number of Units Acquired on Vesting [1] (#)	Value Realized on Vesting [1] ($)
Michael J. Bradley	30,000	$646,800
Thomas E. Long	12,200	261,991
A. Troy Sturrock	4,067	86,956
Jim Holotik	9,200	194,881
Paul M. Jolas	14,734	337,149

(1) Amounts presented represent the number of phantom units vested during 2012 and the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the closing price of our common units upon the vesting date.

Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE ($)
Michael J. Bradley	$—	$—	$—	$ —	$—
Thomas E. Long	—	—	—	—	—
A. Troy Sturrock	—	—	—	—	—
Jim Holotik	—	—	—	—	—
Paul M. Jolas	68,400	—	3,497	(13,849)	58,048

The aggregate earnings reflected above for Mr. Jolas are included in his total compensation for 2012 in the "Summary Compensation Table."

A description of the key provisions of the Partnership's deferred compensation plan can be found in the compensation discussion and analysis above.

Potential Payments upon a Termination or Change of Control

As discussed in "Termination Benefits" within the compensation discussion and analysis above, equity incentive plan awards would vest upon a change of control. Such awards are reflected in the Summary Compensation Table and Grants of Plan-Based Awards Table above at 100% of the fair value of the award upon the grant date. To the extent such awards were not already vested as of December 31, 2012, the fair value of the unvested awards at the date are reflected in the Outstanding Equity Awards at Year-End Table above.

Equity Compensation Awards Granted under the 2006 Plan. With respect to the phantom units granted to Mr. Sturrock on May 7, 2010, a termination without cause or resignation for good reason upon or within a 12-month period following any change of control in the future and prior to the end of the performance period would cause the award to automatically become vested at the "maximum" vested percentage of 150% of target. Assuming such an event had occurred on December 31, 2012, the value of the common units that would have been received by Mr. Sturrock would have been $78,417.

The time-based outstanding phantom unit awards held by each named executive officer that were granted in November and December of 2010 under the Regency GP LLC Long-Term Incentive Plan (dated February 3, 2006, the "2006 Plan") would also receive automatic vesting acceleration upon our change of control, or a termination of employment due to the executive's death or disability. In the event that (i) a change of control had occurred on

December 31, 2012, whether or not the executives also incurred a termination of employment, or (ii) the executive's termination of employment with us had terminated due to his death

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or disability, the value of the accelerated vesting for outstanding phantom unit awards would have been as follows: Mr. Bradley, $1,300,800; Mr. Long, $500,808; Mr. Sturrock, $130,080; and Mr. Holotik, $305,688. These amounts were calculated by multiplying the number of phantom unit awards granted under the 2006 Plan and still held by each named executive officer as of December 31, 2012, and multiplying that number by the closing price of our common stock on that date, $21.68.

Under the 2006 Plan phantom award agreements and our 2006 Plan document, the vesting event terms generally are defined as follows. A termination for "cause" is defined as (i) a failure to render material duties to the Partnership to the reasonable satisfaction of the Partnership (other than as a result of physical or mental impairment or other disability); (ii) failure to follow a reasonable, lawful directive of the Partnership, and non-remedy of such failure within 10 days after receipt of written notice from the Partnership of such failure; (iii) material violation of the policies or procedures of the Partnership; (iv) engagement in misconduct in connection with the performance of duties for the Partnership, including but not limited to a material act of fraud, embezzlement, misappropriation, willful misconduct or breach of fiduciary duty against the Partnership; (v) plea of guilty to or conviction of any felony; or (vi) unlawful use or possession of illegal drugs on Partnership premises or while performing duties and responsibilities for the Partnership. A "good reason" termination, if applicable, means a material reduction in the executive's base salary or target bonus following a change of control. While any individual award agreement may contain a modified definition of a "change of control," the term is generally defined pursuant to our 2006 Plan as the occurrence of one or more of the following events: (1) any person or group becomes the beneficial owner of 50 percent or more of our voting power or voting securities, unless such person or group is the initial entity controlling the General Partner or an affiliate, (2) the complete liquidation of either the general partner of our General Partner, our General Partner, or us; or (3) the sale of all or substantially all of our General Partner's, or our assets to anyone other than an entity that is wholly owned by one or more of the General Partner, or us. An executive's "disability" will have occurred at the point that the executive would be entitled to receive benefits under our long-term disability plan.

Equity Compensation Awards Granted under the 2011 Plan. The phantom unit agreements granted to certain of our named executive officers on December 21, 2011 and December 17, 2012 were granted under the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"). The phantom unit awards under the 2011 Plan will receive accelerated vesting upon a holder's termination of employment for death or a disability, or upon a change of control. The value of the accelerated vesting for outstanding phantom unit awards under the 2011 Plan in the event of a termination of employment for death or disability, or upon a change of control, as of December 31, 2012, would have been as follows: Mr. Bradley, $1,951,200; Mr. Long, $932,240; Mr. Sturrock, $338,208; and Mr. Holotik, $878,040. These amounts were calculated by multiplying the number of phantom unit awards granted under the 2011 Plan and still held by each named executive officer as of December 31, 2012, by the closing price of our common stock on that date, $21.68.

Under our 2011 Plan phantom unit award agreements and the 2011 Plan document, the vesting event terms are generally defined as follows. A "change of control" generally will occur if (i) any person or group, other than an affiliate of the general partner of our General Partner (the "Company"), shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Company; (ii) the members of the Company approve, in one or a series of transactions, a plan of complete liquidation of the Company; (iii) the sale or other disposition by the Company of all or substantially all of its assets in one or more transactions to any person other than the Company or an affiliate of the Company; or (iv) a person other than the Company, our General Partner or an affiliate of the Company or our General Partner becomes the general partner of the Partnership; however, if a phantom unit award is designed to be subject to Section 409A of the Code, the term "change of control" shall mean a "change of control event" as defined in the regulations under Section 409A of the Code. A "disability" is an illness or injury that lasts at least six continuous months, is expected to be permanent and renders the individual unable to carry out his or her duties to the Board, the general partner of our General Partner, our General Partner, the Partnership or an affiliate of any of the applicable entities.

Deferred Compensation Plan. As discussed in "Deferred Compensation Plan" within the compensation discussion and analysis above, all amounts under the DC Plan (other than discretionary credits) are immediately 100% vested. Upon a change of control, distributions from the DC Plan would be made in accordance with the DC Plan's normal distribution provisions.

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Non-Employee, Independent Director Compensation Table for the Year Ended December 31, 2012

Our Board of Directors annually determines the amounts payable to the members of our Board of Directors. In 2012, the directors of the General Partner who were not employees of the General Partner received an annual retainer of $40,000, a flat fee of $1,500 for each meeting of the board attended in person, $1,000 for each committee meeting attended in person, a flat fee of $500 for each such meeting attended by telephone and fees at specified rates for consulting services. In addition, the Chairman of our Audit and Risk Committee receives an annual fee of $10,000.

Name	Fees Paid in Cash ($) (1)	Unit Awards ($) (2)	Total ($)
James W. Bryant	$51,000	$—	$51,000
Rodney L. Gray	62,000	—	62,000
John D. Harkey, Jr.	51,500	—	51,500

(1) Fees paid in cash are based on amounts paid during the period.

(2) No unit awards were granted during the period.

As of December 31, 2012, Messrs. Bryant, Gray and Harkey had 1,215, 4,548, and 10,068 unit awards outstanding, respectively.

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

The following table sets forth, as of February 22, 2013, the beneficial ownership of our units by:

- each person who then owned beneficially 5% or more of our common units;
- each member of the Board of Directors of Regency GP LLC;
- each named executive officer of Regency GP LLC; and
- all directors and executive officers of Regency GP LLC, as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities with respect to which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

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Name of Beneficial Owners	Business Address	Common Units	Percentage of Outstanding Common Units
Energy Transfer Equity, L.P., LE GP, LLC, Kelcy L. Warren (1)	3738 Oak Lawn Avenue, Dallas, Texas, 75219	26,266,791	15.4%
Tortoise Capital Advisors, L.L.C. (2)	11550 Ash Street, Suite 300 Leawood, KS 66211	15,769,382	9.2%
Kayne Anderson Capital Advisors, L.P. (3)	1800 Avenue of the Stars Second Floor Los Angeles, CA 90067	12,999,660	7.6%
Neuberger Berman Group LLC (4)	605 Third Avenue New York, NY 10158	11,764,921	6.9%
Michael J. Bradley	2001 Bryan Street, Suite 3700 Dallas, TX 75219	39,266	*
Thomas E. Long	2001 Bryan Street, Suite 3700 Dallas, TX 75219	14,633	*
A. Troy Sturrock	2001 Bryan Street, Suite 3700 Dallas, TX 75219	20,370	*
Jim Holotik	2001 Bryan Street, Suite 3700 Dallas, TX 75219	10,971	*
James W. Bryant	2001 Bryan Street, Suite 3700 Dallas, TX 75219	607	*
Rodney L. Gray	2001 Bryan Street, Suite 3700 Dallas, TX 75219	7,274	*
John D. Harkey, Jr.	2001 Bryan Street, Suite 3700 Dallas, TX 75219	5,033	*
John W. McReynolds	2001 Bryan Street, Suite 3700 Dallas, TX 75219	—	*
All directors and executive officers as a group (8 persons)		98,154	0.1%
Total number of units as of February 22, 2013		170,951,735	

(1) Based solely on the Schedule 13D/A filed with the SEC on December 13, 2010, ETE, LE GP, LLC (“LE GP”) and Kelcy L. Warren are the beneficial owners of 26,266,791 common units. ETE, LE GP and Mr. Warren have the sole power to vote and dispose of 26,266,791 common units. Ray C. Davis, through his ownership interest in LE GP, may be deemed to also beneficially own the common units that are beneficially owned by ETE, LE GP and Mr. Warren to the extent of his interest in LE GP.

(2) Based solely on the Schedule 13G filed with the SEC on February 12, 2013, Tortoise Capital Advisors, L.L.C. (“TCA”) acts as an investment adviser to certain investment companies registered under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over securities owned of record by these investment companies. However, despite

their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owners under Rule 13d-3 of the Exchange Act of the securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with TCA. Thus, TCA has reported that it shares voting power and dispositive power over the securities owned of record by these investment companies. TCA also acts as an investment adviser to certain managed accounts. Under contractual agreements with individual account holders, TCA, with respect to the securities held in the managed accounts, shares investment and voting power with certain account holders, and has no voting power but shares investment power with certain other account holders. TCA may be deemed the beneficial owner of the securities under Rule 13d-3 of the Exchange Act. Of the 15,769,382 common units reported as beneficially owned by TCA, TCA has reported that it has shared voting power with respect to 15,060,825 of these common units and shared dispositive power with respect to all of these common units. None of these securities are owned of record by TCA, and TCA disclaims any beneficial interest in such securities. The source of the foregoing information is such Schedule 13G/A.

(3) Based solely on the Schedule 13G filed with the SEC on January 10, 2013.

(4) Based solely on the Schedule 13G/A filed with the SEC on February 14, 2013.

* Less than 1.0%

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Our General Partner's Board of Directors, or its Compensation Committee, in its discretion may terminate, suspend or discontinue the LTIP at any time with respect to any award that has not yet been granted. Our General Partner's Board of Directors, or its Compensation Committee, also has the right to alter or amend the LTIP or any part of the plan from time to time, including increasing the number of units that may be granted subject to unitholder approval as required by the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.
The following table summarizes the number of securities remaining available for future issuance under our LTIP plans as of December 31, 2012:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Plans (Excluding Securities Reflected in Column[(a)])
	(a)	(b)	(c)
Equity compensation plans approved by security holders 2011 Long-Term Incentive Plan	867,835	$ —	2,064,487
Equity compensation plans not approved by security holders 2006 Long-Term Incentive Plan (1)	363,507 *		—
Total	1,231,342	$ —	2,064,487

* Assumes performance-based phantom unit grants vest at 100%.
(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 2,865,584 units, which grant did not require approval by our limited partners.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The Board of Directors appoints independent directors as members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to us and our common unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to us to determine whether the transaction is fair and reasonable to us. Our partnership agreement provides that any matter approved by the Conflicts Committee will be deemed approved by all partners of us and not a breach by the General Partner or its affiliates of the partnership agreement or of any duty they may owe us or our unitholders. The Conflicts Committee is composed only of independent directors.
ETE owns all of the limited partnership interest in the General Partner, all of the membership interest in the general partner of the General Partner and 100% of the IDRs. Two of the five current directors of the General Partner are also directors of LE GP, LLC, which is the general partner of ETE. As of December 31, 2012, ETE owned approximately 15% of our outstanding common units. In conjunction with our distributions to the limited and general partner interests, ETE received cash distributions, including IDRs, of $62 million in 2012.
We have a services agreement with ETE and Services Co., in which Services Co. performs certain general and administrative services for us. We also have an operating and service agreement with ETC, in which ETC provides certain operations, maintenance and related services for us. We incurred $17 million of total service fees in 2012.
Our Gathering and Processing segment, in the normal course of business, sells natural gas and NGLs to, and purchases natural gas and NGLs from, subsidiaries of ETE. In 2012, our Gathering and Processing segment recorded revenues from subsidiaries of ETE of $13 million, and cost of sales to subsidiaries of ETE of $2 million.
Our Contract Services segment provides contract compression services to ETE and recorded $4 million in revenues in 2012 in gathering, transportation and other fees on the statement of operations. In addition, during 2012, our Contract Services segment purchased property, plant and equipment of $29 million from a subsidiary of ETE, and sold

property, plant and equipment of $1 million to a subsidiary of ETE.

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Item 14. Principal Accountant Fees and Services

Appointment of Independent Registered Public Accountant. The Audit and Risk Committee retained Grant Thornton LLP as our principal accountant to conduct the audit of our financial statements for the years ended December 31, 2012 and 2011.

Audit Fees. The following table sets forth fees billed by Grant Thornton LLP for the professional services rendered for the audits of our annual financial statements and other services rendered for the years ended December 31, 2012 and 2011.

	December 31,	
	2012	2011
Audit fees[1]	$1,207,500	$946,000

(1) Includes fees for audits of annual financial statements, including the audit of internal control over financial reporting, reviews of related quarterly financial statements, and services that are normally provided by independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC.

Procedures for Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accountant. Pursuant to the charter of the Audit and Risk Committee, the Audit and Risk Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit and Risk Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and to establish the fees and other compensation to be paid to our external auditors. The Audit and Risk Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit and Risk Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountant.

The Audit and Risk Committee reviews the external auditors' proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors' internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two fiscal years; and
- the rotation of the lead partner.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a)1. Financial Statements. See "Index to Financial Statements" set forth on page F-1.

(a)2. Financial Statement Schedules. Other schedules are omitted because they are not required or applicable, or the required information is included in the Consolidated Financial Statements or related notes.

(a)3. Exhibits. See "Index to Exhibits."

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

REGENCY ENERGY PARTNERS LP

By: REGENCY GP LP, its general partner
By: REGENCY GP LLC, its general partner

By: /s/ MICHAEL J. BRADLEY
Michael J. Bradley
President and Chief Executive Officer and officer duly authorized to sign on behalf of the registrant

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated:

Signature	Title	Date
/s/ MICHAEL J. BRADLEY Michael J. Bradley	President, Chief Executive Officer (Principal Executive Officer) and Director	March 1, 2013
/s/ THOMAS E. LONG Thomas E. Long	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2013
/s/ A. TROY STURROCK A. Troy Sturrock	Vice President, Controller (Principal Accounting Officer)	March 1, 2013
/s/ JAMES W. BRYANT James W. Bryant	Director	March 1, 2013
/s/ RODNEY L. GRAY Rodney L. Gray	Director	March 1, 2013
/s/ JOHN D. HARKEY, JR. John D. Harkey, Jr.	Chairman of the Board of Directors	March 1, 2013
/s/ JOHN W. MCREYNOLDS John W. McReynolds	Director	March 1, 2013

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Index to Exhibits

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
2.1	Purchase Agreement, dated as of March 22, 2011, by and among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC, Louis Dreyfus Highbridge Energy LLC and, for the limited purposes set forth therein, Energy Transfer Partners, L.P. and Regency Energy Partners LP	8-K/A	March 25, 2011
2.2	Contribution Agreement dated of February 27, 2013	8-K	February 28, 2013
3.1	Certificate of Limited Partnership of Regency Energy Partners LP	S-1	333-128332
3.2	Form of Amended and Restated Limited Partnership Agreement of Regency Energy Partners LP (included as Appendix A to the Prospectus and including specimen unit certificate for the common units)	S-1	333-128332
3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	August 14, 2006
3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	September 21, 2006
3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	January 8, 2008
3.2.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	January 16, 2008
3.2.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	August 28, 2008
3.2.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	February 27, 2009
3.2.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	September 4, 2009
3.3	Certificate of Formation of Regency GP LLC	S-1	333-128332
3.4	Form of Amended and Restated Limited Liability Company Agreement of Regency GP LLC	S-1	333-128332
3.4.1	First Amendment to Amended and Restated Limited Liability Company Agreement of Regency GP LLC	10-K	March 1, 2010

3.4.2	Second Amendment to Amended and Restated Limited Liability Company Agreement of Regency GP LLC	8-K	August 10, 2010
3.4.3	Third Amendment to Amended and Restated Limited Liability Company Agreement of Regency GP LLC	8-K	January 6, 2011
3.5	Certificate of Limited Partnership of Regency GP LP	S-1	333-128332
3.6	Form of Amended and Restated Limited Partnership Agreement of Regency GP LP	S-1	333-128332
3.7	Second Amended and Restated General Partnership Agreement of RIGS Haynesville Partnership Co. dated as of December 18, 2009	10-K	March 1, 2010
3.7.1	First Amendment to Second Amended and Restated General Partnership Agreement of RIGS Haynesville Partnership Co. dated as of March 9, 2010	10-Q	May 7, 2010
4.1	Form of Common Unit Certificate	S-1	333-128332
4.2	Indenture for 9.375% Senior Notes due 2016, together with the global notes	10-Q	August 10, 2009
4.3	Registration Rights Agreement for 9.375% Senior Notes due 2016	10-Q	August 10, 2009

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
4.4	Registration Rights Agreement dated May 26, 2010 by and between Energy Transfer Equity, L.P. and Regency Energy Partners LP	8-K	May 28, 2010
4.5	Registration Rights Agreement dated May 26, 2010 by and among Regency LP Acquirer, L.P. and Regency Energy Partners LP	8-K	May 28, 2010
4.6	Investor Rights Agreement dated as of May 26, 2010 by and among Regency LP Acquirer LP, Regency GP LP and Regency GP LLC	8-K	May 28, 2010
4.7	First Supplemental Indenture dated October 26, 2010 among the Guaranteeing Subsidiaries, Regency Energy Partners LP, Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee	10-K	February 18, 2011
4.8	Indenture dated October 27, 2010 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee	8-K	October 27, 2010
4.9	First Supplemental Indenture dated October 27, 2010 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee	8-K	October 27, 2010
4.10	Registration Rights Agreement dated May 2, 2011 by and among Regency Energy Partners LP and the purchasers set forth on Schedule I thereto.	8-K	May 2, 2011
4.11	Second Supplemental Indenture dated May 24, 2011 among the Guaranteeing Subsidiaries, Regency Energy Partners LP, Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee.	8-K	May 26, 2011
4.12	Second Supplemental Indenture dated May 24, 2011 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee	8-K	May 26, 2011
4.13	Third Supplemental Indenture dated May 26, 2011 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee	8-K	May 26, 2011
4.14	Regency Energy Partners LP 2011 Long-Term Incentive Plan	8-K	December 20, 2011

4.15	Form of Grant of Phantom Units with DERs	8-K	December 20, 2011
4.16	Third Supplemental Indenture dated May 22, 2012 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	POSASR	333-169901
4.17	Fourth Supplemental Indenture dated May 22, 2012 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee.	POSASR	333-169901
4.18	Fifth Supplemental Indenture dated October 2, 2012 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee (including the form of the Notes).	8-K	October 2, 2012
4.19	Form of Grant of Phantom Units with DERs	*	
10.1	Regency GP LLC Long-Term Incentive Plan	S-1	333-128332
10.2	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan—Unit Option Grant	S-1	333-128332
10.3	Form of Indemnification Agreement between Regency GP LLC and Indemnities	S-1	333-128332

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
10.4	Amended and Restated Master Services Agreement, dated as of December 18, 2009, by and between RIGS Haynesville Partnership Co., a Delaware general partnership, and Regency Employees Management LLC, a Delaware limited liability company	10-K	March 1, 2010
10.5	Area of Mutual Interest Agreement, dated as of March 17, 2009, by and among Regency Energy Partners LP, a Delaware limited partnership, RIGS Haynesville Partnership Co., a Delaware general partnership, Regency Haynesville Intrastate Gas LLC, a Delaware limited liability company, Alinda Gas Pipeline I, L.P., a Delaware limited partnership, and Alinda Gas Pipeline II, L.P., a Delaware limited partnership	8-K	March 18, 2009
10.6	Series A Cumulative Convertible Preferred Unit Purchase Agreement, dated September 2, 2009, by and among Regency Energy Partners LP and the purchasers named therein	8-K	September 4, 2009
10.7	Fifth Amended and Restated Credit Agreement, dated March 4, 2010	8-K	March 4, 2010
10.8	Amendment Agreement to the Fifth Amended and Restated Credit Agreement, dated March 4, 2010	8-K	March 4, 2010
10.9	Voting Agreement, dated April 30, 2010, by and between EFS Haynesville, LLC and Regency Haynesville Intrastate Gas LLC	8-K	April 30, 2010
10.10	Form of Grant of Phantom Units—Service Vesting	8-K	May 11, 2010
10.11	Form of Grant of Phantom Units—Performance Vesting	8-K	May 11, 2010
10.12	Amendment Agreement No. 1 to the Fifth Amended and Restated Credit Agreement.	8-K	May 28, 2010
10.13	Services Agreement dated May 26, 2010 by and among ETE Services Company, LLC, Energy Transfer Equity, L.P. and Regency Energy Partners LP	8-K	May 28, 2010
10.14	Purchase and Sale Agreement by and among Regency Field Services LLC, Tristream East Texas, LLC and Tristream Energy, LLC dated July 15, 2010.	10-Q	August 9, 2010
10.15	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan—Phantom Unit Grant (With DERs).	10-K	February 18, 2011

10.16	Assumption, Contribution and Indemnification Agreement, dated as of March 22, 2011, between Energy Transfer Partners, L.P. and Regency Energy Partners LP	8-K/A	March 25, 2011
10.17	Common Unit Purchase Agreement, dated March 23, 2011, by and among Regency Energy Partners LP and the purchasers named therein.	8-K	March 28, 2011
10.18	Amendment Agreement No. 2 to the Fifth Amended and Restated Credit Agreement, dated May 2, 2011.	8-K	May 2, 2011
10.19	Amended and Restated Limited Liability Company Agreement of ETP-Regency Midstream Holdings, LLC, dated May 2, 2011.	8-K	May 2, 2011
10.20	Operation and Service Agreement by and between La Grange Acquisition, L.P., Regency GP LP, Regency Energy Partners LP and Regency Gas Services LP, dated May 19, 2011.	8-K	May 19, 2011
10.21	Amendment Agreement No. 3 to the Fifth Amended and Restated Credit Agreement, dated December 15, 2011	8-K	December 16, 2011
10.22	Separation Agreement and Full Release of Claims dated January 27, 2012, by and between Regency GP LLC and Paul M. Jolas.	8-K	January 31, 2012

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
10.23	Increase Joinder to the Fifth Amended and Restated Credit Agreement dated as of August 22, 2012.	8-K	August 24, 2012
10.24	Amendment Agreement No. 4 to the Fifth Amended and Restated Credit Agreement, dated February 15, 2013	8-K	February 19, 2013
12.1	Computation of Ratio of Earnings to Fixed Charges.	*	
21.1	List of Subsidiaries of Regency Energy Partners LP	*	
23.1	Consent of Grant Thornton LLP.	*	
23.2	Consent of Grant Thornton LLP.	*	
23.3	Consent of Grant Thornton LLP.	*	
23.4	Consent of KPMG LLP.	*	
23.5	Consent of KPMG LLP.	*	
23.6	Consent of PricewaterhouseCoopers LLP.	*	
23.7	Consent of Ernst & Young LLP.	*	
31.1	Certifications pursuant to Rule 13a-14(a).	*	
31.2	Certifications pursuant to Rule 13a-14(a).	*	
32.1	Certifications pursuant to Section 1350.	**	
32.2	Certifications pursuant to Section 1350.	**	
99.1	Statement of Policies Relating to Potential Conflicts among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P., and Regency Energy Partners LP dated as of April 26, 2011.	10-Q	August 8, 2011
99.2	Audited Financial Statements of RIGS Haynesville Partnership Co. as of December 31, 2012 and 2011 and for the years then ended.	*	
99.3	Audited Financial Statements of RIGS Haynesville Partnership Co. as of and for the year ended December 31, 2010 and for the period from March 18, 2009 to December 31, 2009.	*	
99.4		*	

	Audited Financial Statements of Midcontinent Express Pipeline LLC as of December 31, 2012 and 2011 and for the years then ended.		
99.5	Audited Financial Statements of Midcontinent Express Pipeline LLC for the year ended December 31, 2011 and the seven months ended December 31, 2010.	*	
99.6	Audited Financial Statements of Lone Star NGL LLC as of and for the year ended December 31, 2012 and for the period from March 21, 2011 to December 31, 2011.	*	
99.7	Audited Financial Statements of LDH Energy Asset Holdings LLC as of December 31, 2010 and 2009, and for the three-year period ended December 31, 2010.	*	
99.8	Regency Energy Partner LP Notice of Beginning of Administrative Proceedings for Tax Year December 31, 2008.	10-K	March 1, 2010
99.9	Regency Energy Partner LP Notice of Beginning of Administrative Proceedings for Tax Year December 31, 2007.	10-K	March 1, 2010

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
101.INS	XBRL Instance Document		
101.SCH	XBRL Taxonomy Extension Schemat		
101.CAL	XBRL Taxonomy Extension Calculation Linkbase		
101.DEF	XBRL Taxonomy Extension Definition Linkbase		
101.LAB	XBRL Taxonomy Extension Label Linkbase		
101.PRE	XBRL Taxonomy Extension Presentation Linkbase		

*Filed herewith
**Furnished herewith

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Index to Consolidated Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Regency Energy Partners LP
We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners' capital and noncontrolling interest for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Partnership's investment in which is accounted for under the equity method of accounting. The Partnership's investment in Midcontinent Express Pipeline LLC as of December 31, 2012 and 2011 was $581 million and $614 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $42 million and $43 million, respectively, for the years then ended. Those statements were audited by other auditors, whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the report of the other auditors.
We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.
In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency Energy Partners LP and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 1, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Regency Energy Partners LP
We have audited the internal control over financial reporting of Regency Energy Partners LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2012 and our report dated March 1, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 1, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners
Regency Energy Partners LP:

We have audited the accompanying consolidated statements of operations, comprehensive income (loss), cash flows, and partners' capital and noncontrolling interest for the period from May 26, 2010 to December 31, 2010 and the period from January 1, 2010 to May 25, 2010 for Regency Energy Partners LP and subsidiaries. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements of Midcontinent Express Pipeline LLC, (a 49.9% owned investee company which was acquired by the Partnership on May 26, 2010). The Partnership's equity in the earnings of Midcontinent Express Pipeline LLC was $21,219,000 for the period from May 26, 2010 to December 31, 2010. The financial statements of Midcontinent Express Pipeline LLC were audited by other auditors whose report has been furnished to us and included herein, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows for the period from May 26, 2010 to December 31, 2010 and the period from January 1, 2010 to May 25, 2010 for Regency Energy Partners LP and subsidiaries, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Dallas, Texas
February 18, 2011

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Regency Energy Partners LP
Consolidated Balance Sheets
(in millions except unit data)

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$53	$1
Trade accounts receivable, net of allowance of $1 and $1	40	44
Accrued revenues	107	68
Related party receivables	4	45
Derivative assets	4	4
Other current assets	29	25
Total current assets	237	187
Property, Plant and Equipment:		
Gathering and transmission systems	852	699
Compression equipment	961	847
Gas plants and buildings	232	195
Other property, plant and equipment	189	148
Construction-in-progress	283	192
Total property, plant and equipment	2,517	2,081
Less accumulated depreciation	(355)	(195)
Property, plant and equipment, net	2,162	1,886
Other Assets:		
Investment in unconsolidated affiliates	2,214	1,925
Long-term derivative assets	1	—
Other, net of accumulated amortization of debt issuance costs of $17 and $10	41	39
Total other assets	2,256	1,964
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $74 and $45	712	741
Goodwill	790	790
Total intangible assets and goodwill	1,502	1,531
TOTAL ASSETS	$6,157	$5,568
LIABILITIES & PARTNERS’ CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$6	$3
Trade accounts payable	102	73
Accrued cost of gas and liquids	83	85
Related party payables	37	13
Deferred revenues	17	16
Derivative liabilities	1	11
Other current liabilities	41	33
Total current liabilities	287	234
Long-term derivative liabilities	25	39
Other long-term liabilities	5	6
Long-term debt, net	2,157	1,687
Commitments and contingencies		
Series A Preferred Units, redemption amount of $85 and $85	73	71
Partners’ Capital and Noncontrolling Interest:		

Common units (174,574,175 and 161,233,046 units authorized; 170,951,457 and 157,437,608 units issued and outstanding at December 31, 2012 and 2011)	3,207	3,173
General partner interest	326	330
Accumulated other comprehensive loss	—	(5)
Total partners’ capital	3,533	3,498
Noncontrolling interest	77	33
Total partners’ capital and noncontrolling interest	3,610	3,531
TOTAL LIABILITIES AND PARTNERS’ CAPITAL AND NONCONTROLLING INTEREST	$6,157	$5,568

See accompanying notes to consolidated financial statements

Regency Energy Partners LP
Consolidated Statements of Operations
(in millions except unit data and per unit data)

	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
REVENUES				
Gas sales, including related party amounts of $21, $23, $3, and $0	$329	$456	$291	$228
NGL sales, including related party amounts of $24, $365, $137, and $0	539	603	238	153
Gathering, transportation and other fees, including related party amounts of $31, $24, $14, and $12	403	351	179	115
Net realized and unrealized gain (loss) from derivatives	11	(19)	(8)	(1)
Other, including related party amounts of $1, $10, $3, and $0	57	43	16	10
Total revenues	1,339	1,434	716	505
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $16, $22, $13, and $7	871	1,013	504	358
Operation and maintenance	166	147	78	48
General and administrative, including related party amounts of $17, $17, $6, and $0	63	67	44	37
Loss (gain) on asset sales, net	3	(2)	—	—
Depreciation and amortization	201	169	76	42
Total operating costs and expenses	1,304	1,394	702	485
OPERATING INCOME	35	40	14	20
Income from unconsolidated affiliates	114	120	54	16
Interest expense, net	(122)	(103)	(48)	(35)
Loss on debt refinancing, net	(8)	—	(16)	(2)
Other income and deductions, net	30	17	(8)	(4)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	49	74	(4)	(5)
Income tax expense	1	—	1	—
INCOME (LOSS) FROM CONTINUING OPERATIONS	$48	$74	$(5)	$(5)
DISCONTINUED OPERATIONS				
Net loss from operations of east Texas assets	—	—	(1)	—
NET INCOME (LOSS)	$48	$74	$(6)	$(5)
Net income attributable to noncontrolling interest	(2)	(2)	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$46	$72	$(6)	$(5)

Amounts attributable to Series A Preferred Units	10	8	5	3
General partner's interest, including IDRs	9	7	3	1
Limited partners' interest in net income (loss)	$27	$57	$(14)	$(9)
Basic and diluted income (loss) from continuing operations per unit:				
Amount allocated to common units	$27	$57	$(12)	$(9)
Weighted average number of common units outstanding	167,492,735	145,490,869	130,619,554	92,788,319
Basic income (loss) from continuing operations per common unit	$0.16	$0.39	$(0.09)	$(0.10)
Diluted income (loss) from continuing operations per common unit	$0.13	$0.32	$(0.09)	$(0.10)
Distributions per unit	$1.84	$1.81	$0.89	$0.89
Basic and diluted loss on discontinued operations per unit	$—	$—	$(0.01)	$—
Basic and diluted net income (loss) per unit:				
Amount allocated to common units	$27	$57	$(14)	$(9)
Basic net income (loss) per common unit	$0.16	$0.39	$(0.10)	$(0.10)
Diluted net income (loss) per common unit	$0.13	$0.32	$(0.10)	$(0.10)

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP
Consolidated Statements of Comprehensive Income (Loss)
(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
Net income (loss)	$48	$74	$(6)	$(5)
Other comprehensive income (loss):				
Net cash flow hedge amounts reclassified to earnings	5	19	—	2
Change in fair value of cash flow hedges	—	(13)	(11)	18
Total other comprehensive income (loss)	$5	$6	$(11)	$20
Comprehensive income (loss)	$53	$80	$(17)	$15
Comprehensive income attributable to noncontrolling interest	2	2	—	—
Comprehensive income (loss) attributable to Regency Energy Partners LP	$51	$78	$(17)	$15

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP
Consolidated Statements of Cash Flows
(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
OPERATING ACTIVITIES				
Net income (loss)	$48	$74	$(6)	$(5)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:				
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	209	175	79	49
Write-off of debt issuance costs and bond premium	(1)	—	(1)	2
Income from unconsolidated affiliates	(114)	(120)	(54)	(16)
Derivative valuation changes	(19)	(21)	33	12
Loss (gain) on asset sales, net	3	(2)	—	—
Unit-based compensation expenses	5	3	2	12
Cash flow changes in current assets and liabilities:				
Trade accounts receivable, accrued revenues and related party receivables	7	(8)	—	(11)
Other current assets and other current liabilities	4	11	(13)	25
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(10)	23	(15)	9
Distributions received from unconsolidated affiliates	121	119	57	12
Cash flow changes in other assets and liabilities	(1)	—	(2)	—
Net cash flows provided by operating activities	252	254	80	89
INVESTING ACTIVITIES				
Capital expenditures	(436)	(406)	(159)	(64)
Capital contributions to unconsolidated affiliates	(356)	(53)	(86)	(20)
Distributions in excess of earnings of unconsolidated affiliates	83	74	59	—
Acquisition of investment in unconsolidated affiliates, net of cash received	—	(594)	5	(75)
Acquisitions, net of cash of $-, $-, $2, and $-	—	—	(192)	—
Proceeds from asset sales	26	24	76	11

Net cash flows used in investing activities	(683)	(955)	(297)	(148)
FINANCING ACTIVITIES				
Net (repayments) borrowings under revolving credit facility	(140)	47	(334)	199
Proceeds from issuance of senior notes	700	500	600	—
Redemption of senior notes	(88)	—	(358)	—
Debt issuance costs	(15)	(10)	(11)	(16)
Partner contributions	—	—	28	—
Partner distributions	(322)	(274)	(119)	(86)
Acquisition of assets between entities under common control in excess of historical cost	—	—	—	(17)
Contributions (distributions) from/to noncontrolling interest	42	—	—	(1)
Drafts payable	3	2	—	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	(1)	—	1	(5)
Common unit offerings, net of issuance costs	312	436	400	—
Distributions to Series A Preferred Units	(8)	(8)	(4)	(2)
Net cash flows provided by financing activities	483	693	203	72
Net change in cash and cash equivalents	52	(8)	(14)	13
Cash and cash equivalents at beginning of period	1	9	23	10
Cash and cash equivalents at end of period	$53	$1	$9	$23

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Supplemental cash flow information:				
Non-cash capital expenditures and capital contributions to unconsolidated affiliates	$83	$24	$20	$18
Issuance of common units for investment in unconsolidated affiliate	—	—	584	—
Deemed contribution from acquisition of assets between entities under common control	—	—	9	—
Release of escrow payable from restricted cash	—	—	1	1
Interest paid, net of amounts capitalized	112	83	58	5
Income taxes paid	—	2	1	—

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP
Consolidated Statements of Partners' Capital and Noncontrolling Interest
(in millions except unit data)

Predecessor	Units Common	Common Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance— December 31, 2009	93,188,353	$1,212	$19	$ (2)	$ 14	$1,243
Issuance of common units under LTIP, net of forfeitures and tax withholding	152,075	(5)	—	—	—	(5)
Unit-based compensation expenses	—	12	—	—	—	12
Accrued distributions to phantom units	—	(1)	—	—	—	(1)
Acquisition of assets between entities under common control in excess of historical costs	—	—	(17)	—	—	(17)
Partner distributions	—	(83)	(3)	—	—	(86)
Distributions to noncontrolling interest	—	—	—	—	(1)	(1)
Net (loss) income	—	(6)	1	—	—	(5)
Distributions to Series A Preferred Units	—	(2)	—	—	—	(2)
Net cash flow hedge amounts reclassified to earnings	—	—	—	2	—	2
Net change in fair value of cash flow hedges	—	—	—	19	—	19
Balance—May 25, 2010	93,340,428	$1,127	$—	$ 19	$ 13	$1,159

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP
Consolidated Statements of Partners' Capital and Noncontrolling Interest—(Continued)
(in millions except unit data)

Successor	Units Common	Common Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance—May 26, 2010	93,340,428	$2,074	$305	$ —	$ 31	$2,410
Private common unit offerings, net of costs	26,266,791	584	—	—	—	584
Public common unit offerings, net of costs	17,537,500	400	—	—	—	400
Issuance of common units under LTIP, net of forfeitures and tax withholding	42,417	(1)	—	—	—	(1)
Proceeds from exercise of common unit options	94,200	2	—	—	—	2
Unit-based compensation expenses	—	2	—	—	—	2
Acquisition of assets between entities under common control below historical costs	—	—	9	—	—	9
Partner contributions	—	7	21	—	—	28
Partner distributions	—	(114)	(5)	—	—	(119)
Net (loss) income	—	(9)	3	—	—	(6)
Distributions to Series A Preferred Units	—	(4)	—	—	—	(4)
Net change in fair value of cash flow hedges	—	—	—	(11)	—	(11)
Balance—December 31, 2010	137,281,336	2,941	333	(11)	31	3,294
Common unit offerings, net of costs	20,000,001	436	—	—	—	436
Issuance of common units under LTIP, net of forfeitures and tax withholding	156,271	—	—	—	—	—
Unit-based compensation expenses	—	3	—	—	—	3
Partner distributions	—	(264)	(10)	—	—	(274)
Net income	—	65	7	—	2	74
Distributions to Series A Preferred Units	—	(8)	—	—	—	(8)
Net cash flow hedge amounts reclassified to earnings	—	—	—	19	—	19
Net change in fair value of cash flow hedges	—	—	—	(13)	—	(13)
Balance—December 31, 2011	157,437,608	3,173	330	(5)	33	3,531
	13,341,129	312	—	—	—	312

Common unit offerings, net of costs						
Issuance of common units under LTIP, net of forfeitures and tax withholding	172,720	(1)	—	—	—	(1)
Unit-based compensation expenses	—	5	—	—	—	5
Partner distributions	—	(309)	(13)	—	—	(322)
Net income	—	37	9	—	2	48
Contributions from noncontrolling interest	—	—	—	—	42	42
Distributions to Series A Preferred Units	—	(8)	—	—	—	(8)
Accretion of Series A Preferred Units	—	(2)	—	—	—	(2)
Net cash flow hedge amounts reclassified to earnings	—	—	—	5	—	5
Balance—December 31, 2012	170,951,457	$3,207	$326	$ —	$ 77	$3,610

See accompanying notes to consolidated financial statements

Regency Energy Partners LP
Notes to Consolidated Financial Statements
(Tabular dollar amounts, except per unit data, are in millions)
1. Organization and Basis of Presentation
Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries (the "Partnership"), a Delaware limited partnership. The Partnership was formed on September 8, 2005, and completed its IPO on February 3, 2006. The Partnership and its subsidiaries are engaged in the business of gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. Regency GP LP is the Partnership's general partner and Regency GP LLC (collectively the "General Partner") is the managing general partner of the Partnership and the general partner of Regency GP LP.
In May 2010, GP Seller completed the sale of all of the outstanding membership interests of the General Partner pursuant to a Purchase Agreement (the "Purchase Agreement") among itself, ETE and ETE GP (the "ETE Acquisition"). Prior to the closing of the Purchase Agreement, GP Seller, an affiliate of GE EFS, owned all of the outstanding limited partner interests in the General Partner and all of the member interests in the general partner of the General Partner and, as a result of that position, controlled the Partnership. As a result of this transaction, the outstanding voting interests of the General Partner and control of the Partnership were transferred from GE EFS to ETE.
In connection with this change in control, the Partnership's assets and liabilities were adjusted to fair value on the closing date (May 26, 2010) by application of "push-down" accounting (the "Push-down Adjustments").
The Partnership applied the guidance in FASB ASC 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), in determining the fair value of partners' capital, which is comprised of the following items:

	May 26, 2010
Fair value of limited partners' interest, based on the number of outstanding Partnership common units and the trading price on May 26, 2010	$2,074
Fair value of consideration paid for general partner interest	305
Noncontrolling interest	31
	$2,410

The Partnership then developed the fair value of its assets and liabilities, with the assistance of third-party valuation experts, using the guidance in FASB ASC 820.

	May 26, 2010
Working capital	$(3)
Gathering and transmission systems	471
Compression equipment	746
Gas plants and buildings	117
Other property, plant and equipment	100
Construction-in-progress	114
Other long-term assets	38
Investment in unconsolidated affiliate	739
Intangible assets	666
Goodwill	790
	$3,778
Less:	
Series A Preferred Units	71
Fair value of long-term debt	1,240
Other long-term liabilities	57
Total fair value of partners' capital	$2,410

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Due to the Push-down Adjustments, the Partnership's consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as "Predecessor" and (2) the period from May 26, 2010 forward, identified as "Successor".

Basis of presentation. The consolidated financial statements of the Partnership have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Other Current Assets and Other Current Liabilities. As of December 31, 2012 and 2011, other current assets included spare parts inventories in the Partnership's Contract Services segment of \$27 million and \$21 million, respectively, and other current liabilities included accrued interest of \$30 million and \$27 million, respectively.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2012 and December 31, 2011 and the periods from May 26, 2010 to December 31, 2010 and January 1, 2010 to May 25, 2010, the Partnership capitalized interest of \$1 million, \$1 million, \$1 million and \$1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

The Partnership accounts for its asset retirement obligations by recognizing on its balance sheet the net present value of any legally-binding obligation to remove or remediate the physical assets that it retires from service, as well as any similar obligations for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Partnership. While the Partnership is obligated under contractual agreements to remove certain facilities upon their retirement, management is unable to reasonably determine the fair value of such asset retirement obligations because the settlement dates, or ranges thereof, were indeterminable and could range up to 95 years, or the undiscounted amounts are immaterial. An asset retirement obligation will be recorded in the periods wherein management can reasonably determine the settlement dates.

Depreciation expense related to property, plant and equipment was \$168 million, \$138 million, \$60 million and \$37 million for the years ended December 31, 2012 and December 31, 2011 and the periods from May 26, 2010 to December 31, 2010 and January 1, 2010 to May 25, 2010, respectively. In March 2012, the Partnership recorded a \$7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy. The adjustment to depreciation expense related to the year ended December 31, 2011 and the period from May 26, 2010 to December 31, 2010 was \$4 million and \$3 million, respectively. Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 20
Compression Equipment	2 - 30

Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

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Intangible Assets. As of December 31, 2012, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership’s future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2012, 2011 or 2010.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of December 31, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership’s most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2012, 2011 or 2010.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2012 and 2011 were immaterial.

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, (iii) contract compression services, and (iv) contract treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression and contract treating services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas and NGLs at a price approximating the index price to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses natural gas, ethane, propane, butane, natural gasoline, and condensate swaps as well as ethane put options to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. In prior years, derivative financial instruments qualifying for hedge accounting treatment have been designated by the Partnership as cash flow hedges. The Partnership entered into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documented the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assessed, both at the inception of the hedge and on an on-going basis, whether the derivatives were highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determined that a derivative was no longer highly effective as a hedge, it would discontinue hedge accounting prospectively by including changes in the fair value of the

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derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions. During the year ended December 31, 2012, none of the Partnership's derivative financial instruments were designated for hedge accounting; therefore the change in market value is recorded as a component of net realized and unrealized (loss) gain from derivatives in the consolidated statements of operations.

Benefits. The Partnership previously provided medical, dental, and other healthcare benefits to employees, including providing a matching contribution for employee contributions to their 401(k) accounts, which vested ratably over 3 years. Effective January 1, 2011, the Partnership’s 401(k) plan merged with and into that of ETP. As a result of the merger, the Partnership’s matching contributions that had not yet fully vested became fully vested, effective immediately. All future matching contributions from the Partnership to the employee 401(k) accounts will vest immediately. The amount of matching contributions for the years ended December 31, 2012 and December 31, 2011 and the period from May 26, 2010 to December 31, 2010 was $3 million, $3 million, and $2 million, respectively, and were recorded in general and administrative expenses. The amount of matching contributions for the period from January 1, 2010 to May 25, 2010 was less than $1 million. The Partnership has no pension obligations or other post-employment benefits.

Beginning January 1, 2013, the Partnership will provide a 3% profit sharing contribution to employee 401(k) accounts for all employees with base compensation of $125,000 or less. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has a wholly-owned subsidiary that is subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership’s deferred tax liabilities of $5 million and $6 million as of December 31, 2012 and 2011, respectively, relate to the difference between the book and tax basis of property, plant and equipment and intangible assets and is included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the “more likely than not” criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2012 and 2011. The Partnership recognized current federal income tax expense of $1 million for the period from May 26, 2010 to December 31, 2010 and less than $1 million for the years ended December 31, 2012 and December 31, 2011 and the period from January 1, 2010 to May 25, 2010, respectively. The Partnership also recognized deferred income tax benefit of $1 million for the year ended December 31, 2012 and less than $1 million using a 35% effective rate for the year ended December 31, 2011 and the periods from May 26, 2010 to December 31, 2010 and January 1, 2010 to May 25, 2010, respectively.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The IRS is also conducting an audit of the 2007 through 2009 tax returns of one of the Partnership’s wholly-owned subsidiaries and has proposed certain adjustments. The subsidiary has filed a protest with the IRS. The statute of limitations for each of these audits has been extended to December 31, 2013.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

Earnings per Unit. Basic net income per common unit is computed through the use of the two-class method, which allocates earnings to each class of equity security based on their participation in distributions and deemed distributions. Accretion of the Series A Preferred Units is considered deemed distributions. Distributions and deemed distributions to the Series A Preferred Units reduce the amount of net income available to the general partner and limited partner interests. The general partners' interest in net income or loss consists of its respective percentage interest, make- whole allocations for any losses allocated in a prior tax year and IDRs. After deducting the General Partner's interest, the limited partners' interest in the remaining net income or loss is allocated to each class of equity units based on distributions and beneficial conversion feature amounts, if applicable, then divided by the weighted average number of common and subordinated units outstanding in each class of security. Diluted net income per common unit is computed by dividing limited partners' interest in net income, after deducting the General Partner's interest, by the weighted average number of units outstanding and the effect of non-vested restricted units, phantom units, Series A Preferred Units and unit options. For special classes of common units issued with a beneficial conversion feature, the amount of the benefit associated with the period is added back to net income and the unconverted class is added to the denominator.

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3. Partners' Capital and Distributions

Equity Distribution Agreement. In June 2012, the Partnership entered into an Equity Distribution Agreement with Citi under which the Partnership may offer and sell common units, representing limited partner interests, having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for the Partnership. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and Citi. The Partnership may also sell common units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of common units to Citi as principal would be pursuant to the terms of a separate agreement between the Partnership and Citi. The Partnership intends to use the net proceeds from the sale of these units for general partnership purposes. As of December 31, 2012, the Partnership has issued 691,129 common units resulting in net proceeds of $15 million.

Public Common Unit Offerings. In March 2012, the Partnership issued 12,650,000 common units representing limited partner interests in a public offering at a price of $24.47 per common unit, resulting in net proceeds of $297 million. In May 2012, the Partnership used the net proceeds from this offering to redeem 35%, or $88 million, in aggregate principal amounts of its outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under the revolving credit facility.

In October 2011, the Partnership issued 11,500,000 common units representing limited partnership interests in a public offering at a price of $20.92 per common unit, resulting in net proceeds of $232 million which were used to repay outstanding borrowings under the revolving credit facility. In August 2010, the Partnership sold 17,537,500 common units and received $408 million in proceeds, inclusive of the General Partner's proportionate capital contribution.

Private Common Unit Offerings. In May 2011, the Partnership sold 8,500,001 common units representing limited partnership interests resulting in net proceeds of $204 million, to partially fund its capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

In May 2010, the Partnership issued 26,266,791 common units, valued at $584 million, to ETE, to purchase a 49.9% interest in MEP. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under Section 4(2) thereof. Subsequently, ETE contributed $12 million as the General Partner's proportionate capital.

Noncontrolling Interest. The Partnership operates ELG, a gas gathering joint venture in south Texas in which other third party companies own a 40% interest, which is reflected on the balance sheet as noncontrolling interest.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the General Partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights. The General Partner is entitled to its proportionate share of all quarterly distributions that the Partnership makes prior to its liquidation. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2% interest in these distributions has been reduced since the Partnership has issued additional units and the General Partner has not contributed a proportionate amount of capital to the Partnership to maintain its General Partner interest. The General Partnership ownership interest as of December 31, 2012 was 1.6%. This General Partner interest is represented by 2,798,872 equivalent units as of December 31, 2012.

The IDRs held by the General Partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner's IDRs are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its general partner interest.

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Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2012 and 2011:

Distribution Date	Cash Distribution (per common unit)
November 14, 2012	$0.460
August 14, 2012	0.460
May 14, 2012	0.460
February 13, 2012	0.460
November 14, 2011	0.455
August 12, 2011	0.450
May 13, 2011	0.445
February 14, 2011	0.445

The Partnership paid a cash distribution of $0.46 per common unit on February 14, 2013.

4. Income per Limited Partner Unit

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the years ended December 31, 2012 and 2011. For the periods from May 26, 2010 to December 31, 2010 and from January 1, 2010 to May 25, 2010, diluted earnings per unit equals basic earnings per unit because all instruments were antidilutive.

	For the Year Ended December 31, 2012			For the Year Ended December 31, 2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income per unit						
Limited Partners’ interest in net income	$27	167,492,735	$0.16	$57	145,490,869	$0.39
Effect of Dilutive Securities:						
Common unit options	—	10,854		—	19,192	
Phantom units *	—	223,325		—	148,388	
Series A Preferred Units	(5)	4,658,700		(10)	4,632,389	
Diluted income per unit	$22	172,385,614	$0.13	$47	150,290,838	$0.32

* Amount assumes maximum conversion rate for market condition awards.

The following data show securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit because to do so would have been antidilutive for the periods presented:

	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
Restricted (non-vested) common units	—	—	—	396,918
Common unit options	—	—	259,650	298,400
Phantom units *	—	—	366,489	369,346
Series A Preferred Units	—	—	4,584,192	4,584,192

* Amount assumes maximum conversion rate for market condition awards.

The partnership agreement requires that the General Partner shall receive a 100% allocation of income until its capital account is made whole for all of the net losses allocated to it in prior years.

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5. Acquisitions and Dispositions

2013

SUGC. In February 2013, the Partnership and Regency Western entered into a contribution agreement with the Southern Union, a wholly owned subsidiary of Holdco, to acquire SUGC for $1.5 billion, subject to customary post-closing adjustments. The Partnership will finance the acquisition by issuing $900 million of common units to Holdco, comprised of $750 million of Partnership common units and $150 million of recently created Class F common units. The Class F common units are entitled to participate in the Partnership's 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 Partnership 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 the Partnership 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 the partnership's 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), the Partnership 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 the Partnership and SUGC instead of reflecting the fair market value of SUCG assets and liabilities. The Partnership will recast its financial statements to include the operations of SUGC from March 26, 2012 (the date upon which common control began).

2011

Lone Star. On May 2, 2011, the Partnership contributed $593 million in cash to Lone Star, in exchange for its 30% interest. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC (subsequently renamed Castleton Commodities International, LLC), for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 common units representing limited partnership interests with net proceeds of $204 million. The remaining portion of the Partnership's capital contribution was funded by additional borrowings under its revolving credit facility.

MEP. On September 1, 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing its total interest in MEP to 50%.

Ranch JV. On December 2, 2011, Ranch JV was formed by the Partnership, APM and CM, each owning a 33.33% interest in the joint venture. Ranch JV processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.

2010

HPC. On April 30, 2010, the Partnership purchased an additional 6.99% general partner interest in HPC from EFS Haynesville, bringing its total general partner interest in HPC to 49.99%. The purchase price of $92 million was funded by borrowings under the Partnership's revolving credit facility. Because this transaction occurred between two entities under common control, partners' capital was decreased by $17 million, which represented a deemed distribution of the excess purchase price over EFS Haynesville's carrying amount of $75 million.

MEP. On May 26, 2010, the Partnership purchased a 49.9% interest in MEP from ETE. The Partnership issued 26,266,791 common units to ETE, valued at $584 million, and received a working capital adjustment of $5 million from ETE that was recorded as an adjustment to investment in unconsolidated affiliates. Because this transaction occurred between two entities under common control, partners' capital was increased by $9 million, which represented a deemed contribution of the excess carrying amount of ETE's investment of $589 million over the purchase price. MEP owns approximately 500 miles of natural gas pipelines that extend from the southeast corner of Oklahoma, across northeast Texas, northern Louisiana, central Mississippi and into Alabama.

Disposition of East Texas Assets. In July 2010, the Partnership sold its gathering and processing assets located in east Texas for $70 million in cash. The financial results of these assets have been reclassified to discontinued operations in accordance with applicable accounting standards. Revenues for these assets for the period from May 26, 2010 to December 31, 2010, the period from January 1, 2010 to May 25, 2010, and the year ended December 31, 2009 were

$10 million, $24 million and $46 million, respectively.

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Zephyr. On September 1, 2010, the Partnership completed the Zephyr acquisition for $193 million in cash that was funded by borrowings under the Partnership's revolving credit facility. Zephyr owns and operates a fleet of equipment used in gas treating. The primary treatment services include carbon dioxide and hydrogen sulfide removal, dehydration, natural gas cooling and BTU management. The acquisition of Zephyr further increased the Partnership's fee-based revenues. From September 1, 2010 through December 31, 2010, revenues and net income attributable to Zephyr's operations of $14 million and $6 million, respectively are included in the Partnership's results of operations. The total purchase price was allocated as follows:

	September 1, 2010
Cash and cash equivalents	$2
Trade accounts receivable	7
Gas plants and buildings	81
Intangible assets	119
Total assets acquired	$209
Trade accounts payable	(8)
Deferred revenues	(7)
Other current liabilities	(1)
Net assets acquired	$193

6. Investment in Unconsolidated Affiliates

As of December 31, 2012, the Partnership has a 49.99% general partner interest in HPC, a 50% membership interest in MEP, a 30% membership interest in Lone Star, and a 33.33% membership interest in Ranch JV. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of December 31, 2012 and 2011 is as follows:

	December 31, 2012	December 31, 2011
HPC	$650	$682
MEP	581	614
Lone Star	948	629
Ranch JV	35	—
	$2,214	$1,925

The following tables summarize the changes in the Partnership's investment activities in each of the unconsolidated affiliates for the years ended December 31, 2012, 2011 and 2010:

	Successor			
	Year Ended December 31, 2012			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$343	$36
Distributions from unconsolidated affiliates	61	75	68	—
Share of unconsolidated affiliates' net income	35	42	44	(1)
Amortization of excess fair value of investment (1)	(6)	—	—	—

	Year Ended December 31, 2011			
	HPC	MEP(2)	Lone Star(3)	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$645	$—
Purchase of additional interest in unconsolidated affiliates	—	1	—	—
Distributions from unconsolidated affiliates	65	83	22	—
Return of investment received	—	—	23	—
Share of unconsolidated affiliates' net income	55	43	28	—
Amortization of excess fair value of investment (1)	(6)	—	—	—

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	Period from Acquisition (May 26, 2010) to December 31, 2010			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$86	N/A	N/A
Distributions from unconsolidated affiliates	53	43	N/A	N/A
Return of investment received	20	—	N/A	N/A
Share of unconsolidated affiliates' net income	36	21	N/A	N/A
Amortization of excess fair value of investment (1)	(3)	—	N/A	N/A
	Predecessor			
	Period from January 1, 2010 to May 25, 2010			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$20	N/A	N/A	N/A
Purchase of additional interest in unconsolidated affiliates	75	N/A	N/A	N/A
Distributions from unconsolidated affiliates	12	N/A	N/A	N/A
Share of unconsolidated affiliates' net income	16	N/A	N/A	N/A

(1) As discussed in Note 1, the Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) In September 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing the total membership interest to 50%.

(3) For the period from initial contribution, May 2, 2011, to December 31, 2011.

N/A The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011, a 30% interest in Lone Star in May 2011 and a 49.9% interest in MEP in May 2010.

7. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as market focus. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts settled against NGLs (propane, butane, and natural gasoline), condensate and natural gas market prices. The Partnership also had put options settled against ethane, which expired in December 2012.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2012, the Partnership had less than $1 million in net hedging gains in AOCI, the majority of which will be amortized to earnings over the next 12 months.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012. As of December 31, 2012, the Partnership had $192 million of outstanding borrowings exposed to variable interest rate risk.

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Credit Risk. The Partnership's resale of NGLs, condensate, and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2012 was $5 million, which would be reduced by $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the condensed consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, for the years ended December 31, 2012 and 2011 are detailed below:

	Assets		Liabilities	
	December 31, 2012	December 31, 2011	December 31, 2012	December 31, 2011
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$—	$4	$—	$10
Total cash flow hedging instruments	—	4	—	10
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	4	—	1	—
Interest rate contracts	—	—	—	1
Long-term amounts				
Commodity contracts	1	—	—	—
Embedded derivatives in Series A Preferred Units	—	—	25	39
Total derivatives not designated as cash flow hedges	5	—	26	40
Total derivatives	$5	$4	$26	$50

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The Partnership's statement of operations for the years ended December 31, 2012, 2011 and 2010 was impacted by derivative instruments activities as detailed below:

		Successor			Predecessor
		Year Ended December 31, 2012	Year Ended December 31, 2011	Period from May 26, 2010 to December 31, 2010	Period from January 1, 2010 to May 25, 2010
		Change in Value Recognized in AOCI on Derivatives (Effective Portion)			
Derivatives in cash flow hedging relationships:					
Commodity derivatives		$—	$(13)	$(11)	$14
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Revenue	$—	$(19)	$—	$(5)
Interest rate swap derivatives	Interest expense	—	—	—	(1)
		$—	$(19)	$—	$(6)
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion			
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Revenue	$—	$—	$—	$(1)
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income			
Derivatives not designated in a hedging relationship:					
Commodity derivatives	Revenue	$(5)	$—	$—	$4
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives			
Derivatives not designated in a hedging relationship:					
Commodity derivatives	Revenue	$16	$—	$(8)	$1
Interest rate swap derivatives	Interest expense	—	—	(4)	(1)
Embedded derivatives	Other income & deductions	14	18	(8)	(4)
		$30	$18	$(20)	$(4)

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8. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31, 2012	December 31, 2011
Senior notes	$1,965	$1,355
Revolving loans	192	332
Total	2,157	1,687
Less: current portion	—	—
Long-term debt	$2,157	$1,687
Availability under revolving credit facility:		
Total credit facility limit	$1,150	$900
Revolving loans	(192)	(332)
Letters of credit	(12)	(19)
Total available	$946	$549

Long-term debt maturities as of December 31, 2012 for each of the next five years are as follows:

Year Ended December 31,	Amount
2013	$—
2014	192
2015	—
2016	162
2017	—
Thereafter	1,800
Total	$2,154 *

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*Excludes unamortized premiums of $3 million as of December 31, 2012.

In the year ended December 31, 2012, the Partnership borrowed $1.56 billion under its revolving credit facility; these borrowings were primarily to fund capital expenditures. During the same period, the Partnership repaid $1.7 billion with proceeds from an equity offering and an issuance of senior notes. In the years ended December 31, 2011 and 2010, the Partnership borrowed $940 million and $603 million, respectively; these funds were used primarily to finance capital expenditures and acquisitions. During the same periods, the Partnership repaid $893 million, and $738 million, respectively, of these borrowings with proceeds from equity offerings.

Revolving Credit Facility. The Partnership, through RGS, has a $1.15 billion revolving credit facility, including the availability for letters of credit of $200 million, that expires on June 15, 2014. As of December 31, 2012, RGS is allowed additional investments in Lone Star of up to $550 million; additional investment in ELG of up to $250 million; investment in Ranch JV of up to $50 million; and additional investment in HPC of up to $250 million less the Partnership’s ownership portion of HPC’s indebtedness. In addition, RGS is allowed an additional investment in any joint venture of up to $250 million.

The revolving credit facility and the guarantees are senior to the Partnership’s and the guarantors’ unsecured obligations, to the extent of the value of the assets securing such obligations.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternative base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 1.50% to 2.25% for base rate loans, 2.50% to 3.25% for Eurodollar loans. The weighted average interest rate on the total amounts outstanding under the Partnership’s revolving credit facility was 2.93% and 3.18% as of December 31, 2012 and 2011, respectively.

RGS must pay (i) a commitment fee ranging from 0.375% to 0.50% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 2.50% to 3.25% per

annum of the average daily amount of such lender's letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.125% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.25, consolidated EBITDA to consolidated interest expense ratio greater than 2.75 and a secured debt to consolidated EBITDA ratio less than 3. At December 31, 2012 and 2011, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the revolving credit facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extensions thereof.

Senior Notes due 2016. In May 2009, the Partnership and Finance Corp. issued $250 million of senior notes in a private placement that mature on June 1, 2016 ("2016 Notes"). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. The Partnership received net proceeds of $236 million upon issuance. The net proceeds were used to partially repay revolving loans under the Partnership's revolving credit facility.

In May 2012, the Partnership redeemed 35%, or $88 million, of the 2016 Notes, bringing the total outstanding principal amount to $162 million. Accordingly, a redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statement of operations and accrued interest of $4 million was paid. In addition, the partnership wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to a loss on debt refinancing, net in the consolidated statement of operations.

Beginning June 1 of the years indicated below, the Partnership may redeem all or part of these notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

June 1 of year ending:	Percentage of Redemption
2013	104.688%
2014	102.344%
2015 and thereafter	100.000%

At any time prior to June 1, 2013, the Partnership may also redeem all or part of the 2016 Notes at a price equal to 100% of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at June 1, 2013 plus (ii) all required interest payments due on the note through June 1, 2013, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Senior Notes due 2018. In October, 2010, the Partnership and Finance Corp. issued $600 million of senior notes that mature on December 1, 2018 ("2018 Notes"). The 2018 Notes bear interest at 6.875% paid semi-annually in arrears on June 1 and December 1, commencing June 1, 2011. The Partnership capitalized $12 million in debt issuance costs that will be amortized to interest expense,

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net over the term of the senior notes. The proceeds were used to redeem the senior notes due 2013 and to partially repay outstanding borrowings under the Partnership's revolving credit facility.

At any time before December 1, 2013, up to 35% of the 2018 Notes may be redeemed at a price of 106.875% plus accrued interest. Beginning December 1 of the years indicated below, the Partnership may redeem all or part of the 2018 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

December 1 of year ending:	Percentage of Redemption
2014	103.438%
2015	101.719%
2016 and thereafter	100.000%

At any time prior to December 1, 2014, the Partnership may also redeem all or part of the 2018 Notes at a price equal to 100% of the principal amount redeemed plus accrued interest and the applicable premium, which equals the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at December 1, 2014 plus (ii) all required interest payments due on the note through December 1, 2014, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Senior Notes due 2021. In May 2011, the Partnership and Finance Corp. issued $500 million in senior notes that mature on July 15, 2021 ("2021 Notes"). The 2021 Notes bear interest at 6.5% payable semi-annually in arrears on January 15 and July 15, commencing January 15, 2012. The Partnership capitalized $10 million in debt issuance costs that will be amortized to interest expense, net over the term of the 2021 Notes. The proceeds were used to repay borrowings outstanding under the Partnership's revolving credit facility.

At any time prior to July 15, 2014, up to 35% of the 2021 Notes may be redeemed at a price of 106.5% plus accrued interest. Beginning on July 15 of the years indicated below, the Partnership may redeem all or part of the 2021 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

July 15 of year ending:	Percentage of Redemption
2016	103.250%
2017	102.167%
2018	101.083%
2019 and thereafter	100.000%

At any time prior to July 15, 2016, the Partnership may also redeem all or part of the 2021 Notes at a price equal to 100% of the principal amount redeemed plus accrued interest and the applicable premium, which equals the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at July 15, 2016 plus (ii) all required interest payments due on the note through July 15, 2016, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Senior Notes due 2023. In October 2012, the Partnership and Finance Corp. issued $700 million in senior notes that mature on April 15, 2023 ("2023 Notes"). The 2023 Notes bear interest at 5.5% payable semi-annually in arrears on April 15 and October 15, commencing April 15, 2013. The Partnership capitalized $13 million in debt issuance costs that will be amortized to interest expense, net over the term of the 2023 Notes. The proceeds were used to repay borrowings outstanding under the Partnership's revolving credit facility.

At any time prior to October 15, 2015, up to 35% of the 2023 Notes may be redeemed at a price of 105.5% plus accrued interest. Beginning on October 15 of the years indicated below, the Partnership may redeem all or part of the 2023 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

October 15 of year ending:	Percentage of Redemption
2017	102.750%
2018	101.833%
2019	100.917%
2020 and thereafter	100.000%

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At any time prior to October 15, 2017, the Partnership may also redeem all or part of the 2023 Notes at a price equal to 100% of the principal amount redeemed plus accrued interest and the applicable premium, which equals the greater of (1) 1% of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at October 15, 2017 plus (ii) all required interest payments due on the note through October 15, 2017, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points, over the principal amount of the note.

Senior Notes Covenants. Upon a change of control, as defined in the indenture, followed by a rating decline within 90 days, each holder of the 2016 Notes, 2018 Notes, 2021 Notes and 2023 Notes (collectively the "Senior Notes") will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101% plus accrued interest and liquidated damages, if any. The Partnership's ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility. Subsequent to the ETE Acquisition, in 2010, no noteholder exercised this option.

The Senior Notes contain various covenants that limit, among other things, the Partnership's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, the Partnership will no longer be subject to many of the foregoing covenants. At December 31, 2012, the Partnership was in compliance with these covenants.

The Senior Notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Finance Corp. and several minor subsidiaries, and by certain of its future subsidiaries. The Senior Notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsecured obligations. The Senior Notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The Senior Notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's revolving credit facility, to the extent of the value of the assets securing such obligations.

Finance Corp. has no operations and will not have revenues other than as may be incidental as co-issuer of the Senior Notes. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its subsidiaries, except for a minor subsidiary, the Partnership has not included condensed consolidated financial information of guarantors of the Senior Notes.

9. Intangible Assets

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2011	$707	$63	$770
Amortization	(26)	(3)	(29)
Balance at December 31, 2011	681	60	741
Amortization	(26)	(3)	(29)
Balance at December 31, 2012	$655	$57	$712

The average remaining amortization periods for customer relations and trade names are 25 and 17 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $29 million.

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10. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps, ethane put options, interest rate swaps, and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps, interest rate swaps, and ethane put options are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Embedded derivatives related to the Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy.

The following table presents the Partnership’s derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31, 2012			Fair Value Measurement at December 31, 2011		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$2	$2	$—	$4	$4	$—
Natural Gas Liquids	1	1	—	—	—	—
Condensate	2	2	—	—	—	—
Total Assets	$5	$5	$—	$4	$4	$—
Liabilities						
Commodity Derivatives:						
Natural Gas Liquids	1	1	—	9	9	—
Condensate	—	—	—	2	2	—
Embedded Derivatives in Series A Preferred Units	25	—	25	39	—	39
Total Liabilities	$26	$1	$25	$50	$11	$39

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Series A Preferred Units:

Unobservable Input	December 31, 2012	
Credit Spread	6.49	%
Volatility	21.38	%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

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The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2012 and 2011. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2012 and 2011.

	Embedded Derivatives in Series A Preferred Units
Balance at January, 2011	$ 57
Change in fair value	(18)
Balance at December 31, 2011	39
Change in fair value	(14)
Balance at December 31, 2012	$ 25

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the senior notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The aggregate fair value and carrying amount of our senior notes at December 31, 2012 was $2.13 billion and $1.96 billion, respectively. As of December 31, 2011, the aggregate fair value and carrying amount of our senior notes was $1.44 billion and $1.35 billion, respectively. The fair value of our senior notes is a Level 1 valuation based on third party market value quotations.

11. Leases

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2012:

For the year ending December 31,	Operating
2013	$2
2014	1
2015	1
2016	1
2017	1
Thereafter	2
Total minimum lease payments	$8

Total rent expense for operating leases, including those leases with terms of less than one year, was $3 million, $3 million, $3 million and $2 million, during the years ended December 31, 2012 and 2011 and the periods from May 26, 2010 to December 31, 2010 and January 1, 2010 to May 25, 2010, respectively.

12. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against RGS, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership's predecessor-in-interest in 1996 under which it purchased all of the helium produced at the Lakin, Kansas processing plant. In September 2004, the Partnership decided to shut down its Lakin plant and contract with a third party for the processing of volumes processed at Lakin; as a result, the Partnership no longer delivered any helium to Keyes. In its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. On May 7, 2010, the jury rendered a verdict in favor of the Partnership. No damages were awarded to the Plaintiffs. Plaintiffs appealed the verdict and on December 2, 2012, the appellate court affirmed the trial court's judgment. Keyes filed a motion for rehearing of the appellate court's ruling, and the court denied rehearing. Plaintiffs had until February 22, 2013 to seek review before the Texas Supreme Court.

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13. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units at a price of $18.30 per unit, less issuance costs and a 4% discount of $3 million for net proceeds of $77 million, exclusive of the General Partner's contribution of $2 million. The Series A Preferred Units are convertible to common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80 million plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value") and accrued interest. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit which began with the quarter ending March 31, 2010. Distributions on the Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Series A Preferred Units, (2) reduces the distributions on the common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Series A Preferred Units, all future distributions on the Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Series A Preferred Unit per quarter, (2) $0.09125 per Series A Preferred Unit per quarter (the "Common Unit Distribution Amount"), payable solely in common units, and (3) $0.09125 per Series A Preferred Unit per quarter (the "PIK Distribution Additional Amount"), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters. Upon the Partnership's breach of certain covenants (a "Covenant Default"), the holders of the Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Series A Preferred Units are convertible, at the holder's option, into common units, provided that the holder must request conversion of at least 375,000 Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of common units issuable is equal to the issue price of the Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price. Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Series A Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to

120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

Holders may elect to convert Series A Preferred Units to common units at any time. As of December 31, 2012, the Series A Preferred Units were convertible to 4,658,700 common units.

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The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for all income statement periods presented. The amount includes the accretion to redemption value of $80 million plus any accrued and unpaid distributions and accrued interest by deducting amounts from partners’ capital over the remaining periods until the mandatory redemption date of September 2, 2029.

	Units	Amount
Balance at January 1, 2011	4,371,586	$71
Accretion to redemption value	—	—
Balance at December 31, 2011	4,371,586	71
Accretion to redemption value	—	2
Balance at December 31, 2012	4,371,586	$73

14. Related Party Transactions

As of December 31, 2012 and 2011, details of the Partnership’s related party receivables and related party payables were as follows:

	December 31, 2012	December 31, 2011
Related party receivables		
ETE	$1	$1
HPC	1	1
EPD	N/A	42
Other	2	1
Total related party receivables	$4	$45
Related party payables		
ETE	$37	$11
Other	—	2
Total related party payables	$37	$13

N/A In January 2012, as described below, EPD sold a significant portion of its ownership in ETE’s common units and currently owns less than 5% of ETE’s outstanding common units. During 2012, EPD was not considered a related party.

Transactions with ETE and its subsidiaries. Under a May 26, 2010 service agreement with Services Co., Services Co. performs certain services for the Partnership. The Partnership pays Services Co.’s direct expenses for these services, plus an annual fee of $10 million, and receives the benefit of any cost savings recognized for these services. The services agreement has a five year term from May 26, 2010 to May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. Also, the Partnership, together with the General Partner and RGS entered into an operation and service agreement (the “Operations Agreement”) with ETC. Under the Operations Agreement, ETC will perform certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership. Pursuant to the Operations Agreement, the Partnership will reimburse ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed-upon by both parties. The Operations Agreement has an initial term of one year and automatically renews on a year-to-year basis upon expiration of the initial term. The Partnership incurred total service fees of $17 million, $17 million and $6 million for the years ended December 31, 2012 and 2011 and during the period from May 26, 2010 to December 31, 2010, respectively.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE received cash distributions of $62 million, $57 million and $28 million for the years ended December 31, 2012 and 2011 and during the period from May 26, 2010 to December 31, 2010, respectively. During the period from May 26, 2010 to December 31, 2010, the Partnership received cash of $7 million from ETE, which represents the portion of the amount of the Partnership’s common unit distribution to be paid to ETE for the period of time that those units were not outstanding (April 1, 2010 to May 25, 2010).

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. ETE made capital contributions aggregating to $21 million, to maintain the General Partner's 2% interest in the Partnership for the period from May 26, 2010 to December 31, 2010. No capital contributions were contributed during the years ended December 31, 2012 and 2011, respectively.

In September 2011, the Partnership purchased a 0.1% interest in MEP from ETP for $1 million in cash.

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The Partnership's Gathering and Processing segment, in the ordinary course of business, sells natural gas to subsidiaries of ETE and records the revenue in gas sales. The Partnership's NGL Services segment, in the ordinary course of business, sells NGLs to subsidiaries of ETE and records the revenue in NGL sales. The Partnership's Contract Services segment provides contract compression services to ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership's Contract Services segment sold compression equipment to a subsidiary of ETP for $1 million and $8 million for the years ended December 31, 2012 and 2011, respectively. As these transactions are between entities under common control, partners' capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership's Contract Services segment purchased compression equipment from a subsidiary of ETP for $29 million and $33 million during the years ended December 31, 2012 and 2011, respectively.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2012 and 2011 and during the periods from May 26, 2010 to December 31, 2010, from January 1, 2010 to May 25, 2010, the related party general and administrative expenses reimbursed to the Partnership were $20 million, $17 million, $10 million and $7 million, respectively, which is recorded in gathering, transportation and other fees on the statements of operations.

The Partnership's Contract Services segment provides compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Transactions with EPD and its subsidiaries. In January 2012, EPD sold a significant portion of its ownership in ETE's common units, and subsequent to that transaction, owns less than 5% of ETE's outstanding common units. As such, EPD is no longer considered a related party. During 2011, EPD owned a portion of ETE's outstanding common units and therefore was considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

15. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of the reporting segment.

	Reportable Segment	Successor Year Ended December 31, 2012	Year Ended December 31, 2011	Period from May 26, 2010 to December 31, 2010	Predecessor Period from January 1, 2010 to May 25, 2010
Customer					
Customer A	Gathering and Processing	$367	$366	$ 132	$ 88
Customer B	Gathering and Processing	—	—	*	52
Supplier					
Supplier A	Gathering and Processing	171	133	—	—

*Amounts are less than 10% of the total revenue or cost of sales.

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

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16. Segment Information

During the fourth quarter of 2012, the Partnership realigned the composition of its segments and updated the segment names to reflect the realignment. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new segment alignment.

The Partnership has five reportable segments: Gathering and Processing, Natural Gas Transportation, NGL Services, Contract Services, and Corporate. The reportable segments are as described below:

Gathering and Processing. The Partnership provides “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 pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes the Partnership's 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. The Partnership owns 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, 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. The Partnership owns 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. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. The Partnership also owns and operates 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 the Partnership’s corporate offices.

The Partnership accounts for intersegment revenues as if the revenues were to third parties, exclusive of certain cost of capital charges.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the Gathering and Processing and the Natural Gas Transportation segments is defined as total revenues, including service fees, less cost of sales. In the Contract Services segment, segment margin is defined as revenues less direct costs.

Management believes segment margin is an important measure because it directly relates to volume, commodity price changes, revenue generating horsepower and revenue generating gallons per minute. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. The Partnership does not record segment margin for its investments in unconsolidated affiliates (HPC, MEP, Lone Star and Ranch JV) because it records its ownership percentages of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

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Results for each period, together with amounts related to each segment are shown below:

	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
External Revenue				
Gathering and Processing	$1,136	$1,226	$607	$439
Natural Gas Transportation	1	1	—	—
NGL Services	—	—	—	—
Contract Services	183	190	99	59
Corporate	19	17	10	7
Eliminations	—	—	—	—
Total	$1,339	$1,434	$716	$505
Intersegment Revenue				
Gathering and Processing	$—	$—	$—	$—
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	21	17	14	9
Corporate	—	—	—	—
Eliminations	(21)	(17)	(14)	(9)
Total	$—	$—	$—	$—
Cost of Sales				
Gathering and Processing	$857	$993	$497	$353
Natural Gas Transportation	(1)	(2)	(3)	(1)
NGL Services	—	—	—	—
Contract Services	15	22	10	6
Corporate	—	—	—	—
Eliminations	—	—	—	—
Total	$871	$1,013	$504	$358
Segment Margin				
Gathering and Processing	$279	$233	$110	$86
Natural Gas Transportation	2	3	3	1
NGL Services	—	—	—	—
Contract Services	189	185	103	62
Corporate	19	17	10	7
Eliminations	(21)	(17)	(14)	(9)
Total	$468	$421	$212	$147
Operation and Maintenance				
Gathering and Processing	$121	$98	$54	$33
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	1	—
Contract Services	66	66	37	24
Corporate	—	—	—	—
Eliminations	(21)	(17)	(14)	(9)
Total	$166	$147	$78	$48
Depreciation and Amortization				

Gathering and Processing	$108	$87	$46	$25
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	86	78	29	16
Corporate	7	4	1	1
Eliminations	—	—	—	—
Total	$201	$169	$76	$42

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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
Income from Unconsolidated Affiliates				
Gathering and Processing	$(1)	$—	$—	$—
Natural Gas Transportation	71	92	54	16
NGL Services	44	28	—	—
Contract Services	—	—	—	—
Corporate	—	—	—	—
Eliminations	—	—	—	—
Total	$114	$120	$54	$16
Expenditures for Long-Lived Assets				
Gathering and Processing	$272	$282	$93	$44
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	164	120	62	18
Corporate	—	4	4	2
Eliminations	—	—	—	—
Total	$436	$406	$159	$64

	December 31, 2012	December 31, 2011
Assets		
Gathering and Processing	$2,244	$1,960
Natural Gas Transportation	1,232	1,297
NGL Services	948	629
Contract Services	1,672	1,621
Corporate	61	61
Eliminations	—	—
Total	$6,157	$5,568
Investment in Unconsolidated Affiliates		
Gathering and Processing	$35	$—
Natural Gas Transportation	1,231	1,296
NGL Services	948	629
Contract Services	—	—
Corporate	—	—
Eliminations	—	—
Total	$2,214	$1,925
Goodwill		
Gathering and Processing	$313	$313
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	477	477
Corporate	—	—

Eliminations	—	—
Total	$790	$790

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The table below provides a reconciliation of total segment margin to net income (loss) from continuing operations before income taxes:

	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
Total segment margin	$468	$421	$212	$147
Operation and maintenance	(166)	(147)	(78)	(48)
General and administrative	(63)	(67)	(44)	(37)
(Loss) gain on assets sales, net	(3)	2	—	—
Depreciation and amortization	(201)	(169)	(76)	(42)
Income from unconsolidated affiliates	114	120	54	16
Interest expense, net	(122)	(103)	(48)	(35)
Loss on debt refinancing, net	(8)	—	(16)	(2)
Other income and deductions, net	30 *	17	(8)	(4)
Income (loss) from continuing operations before income taxes	$49	$74	$(4)	$(5)

* Other income and deductions, net for the year ended December 31, 2012, included a one-time producer payment of $16 million related to an assignment of certain contracts.

17. Equity-Based Compensation

In December 2011, the Partnership's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase the Partnership's common units; awards of the Partnership's restricted units, phantom units and common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of the Partnership and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by the Compensation Committee of the board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of the Partnership's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by the board of directors or the Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of common units available for awards under the plan; however, any material amendment, such as a change in the types of awards available under the plan, would require the approval of the unitholders of the Partnership. The Compensation Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by the board of directors.

LTIP compensation expense of $5 million, $3 million, $2 million and $12 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2012, December 31, 2011 and for the periods from May 26, 2010 to December 31, 2010 and from January 1, 2010 to May 25, 2010, respectively. In 2010, upon the change of control from GE EFS to ETE, all then non-vested restricted and phantom units, exclusive of the May 7, 2010 phantom unit grants described below, vested during the predecessor period and the Partnership recorded a one-time general and administrative charge of $10 million as a result of such unit vesting.

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Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the years ended December 31, 2012, 2011, and 2010 is as follows:

2012

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,850	$ 21.99
Forfeited or expired	(300)	23.73
Outstanding at end of period	156,550	21.96
Exercisable at the end of the period	156,550	

2011

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	201,950	$ 21.93
Exercised	(38,300)	20.84
Forfeited or expired	(6,800)	26.72
Outstanding at end of period	156,850	21.99
Exercisable at the end of the period	156,850	

2010

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	306,651	$ 21.50
Exercised	(100,200)	20.60
Forfeited or expired	(4,501)	23.73
Outstanding at end of period	201,950	21.93
Exercisable at the end of the period	201,950	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 3.4 years. Intrinsic value is the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Restricted (Non-Vested) Units. The fair value of each restricted (non-vested) unit is determined using the grant date closing price of the Partnership’s common units. All outstanding restricted units vested on May 25, 2010, and the Partnership did not issue any additional restricted units during the remainder of 2010, 2011 or 2012. Restricted (non-vested) common unit activity for the year ended December 31, 2010 is as follows:

2010

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	464,009	$28.36
Granted	—	—
Vested	(444,759)	28.19
Forfeited or expired	(19,250)	32.35
Outstanding at the end of period	—	—

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Phantom Units. All phantom units granted prior to November 2010 were in substance two grants composed of (1) service condition grants with graded vesting over three years; and (2) market condition grants with cliff vesting based upon the Partnership's relative ranking in total unitholder return among 20 peer companies. Upon the change in control from GE EFS to ETE, all then-outstanding phantom units, exclusive of the May 7, 2010 grant described below, vested. The service condition grants vested at a rate of 100% and the market condition grants vested at a rate of 150% pursuant to the terms of the awards. Subsequent to November 2010, all phantom units granted are service condition grants that vest at a rate of 100%.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest over the next five years on a cliff basis; by vesting 60% at the end of the third year of service and vesting the remaining 40% at the end of the fifth year of service. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over the next five years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

During 2011, the Partnership awarded 596,320 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next five years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

In November and December 2010, the Partnership awarded 574,700 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next five years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

On November 21, 2010, Mr. Byron R. Kelley, the Partnership's former President and Chief Executive Officer, retired. The Partnership entered into a consulting agreement with Mr. Kelley, pursuant to which Mr. Kelley will provide consulting services to the Partnership for a term of three years and received a grant of 33,000 service condition (time-based) phantom units. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

On May 7, 2010, the Partnership awarded 247,500 phantom units to senior management and certain key employees. These phantom units include a provision that will accelerate vesting (1) upon a change in control and (2) within 12 months of a change in control, if the grantee's employment is terminated by the Partnership without "Cause" (as defined in the Form of Grant of Phantom Units) or the grantee resigns for "Good Reason" (as defined in the Form of Grant of Phantom Units). Distributions related to these unvested phantom units will be accrued and paid upon vesting.

The following table presents phantom unit activity for the years ended December 31, 2012, 2011 and 2010:

2012

Phantom Units	Units		Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,086,393		$ 24.51
Service condition grants	503,625		21.39
Vested service condition	(223,258	)	24.71
Vested market condition	(10,200	)	19.52
Forfeited service condition	(120,868	)	24.85
Forfeited market condition	(4,350	)	19.52
Total outstanding at end of period	1,231,342		23.22

2011

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	742,517	$ 23.61

Service condition grants	596,320	24.55
Vested service condition	(142,520)	24.73
Vested market condition	(8,550)	19.52
Forfeited service condition	(88,474)	24.99
Forfeited market condition	(12,900)	19.52
Total outstanding at end of period	1,086,393	24.51

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2010

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	301,700	$8.63
Service condition grants	716,200	24.72
Market condition grants	148,500	11.89
Vested service condition	(166,173)	11.63
Vested market condition	(200,610)	5.85
Forfeited service condition	(18,787)	20.18
Forfeited market condition	(38,313)	11.43
Total outstanding at end of period	742,517	23.61

The Partnership expects to recognize $25 million of compensation expense related to non-vested phantom units over a period of 5 years.

18. Quarterly Financial Data (Unaudited)

2012	Quarter Ended December 31	Quarter Ended September 30	Quarter Ended June 30	Quarter Ended March 31
Operating revenues	$355	$314	$312	$358
Operating (loss) income	(3)	5	23	10
Net (loss) income attributable to Regency Energy Partners LP	(9)	(2)	29	28
Earnings per common units:				
Basic net (loss) income per common unit	(0.08)	(0.04)	0.14	0.15
Diluted net (loss) income per common unit	(0.08)	(0.04)	0.10	0.14

2011	Quarter Ended December 31	Quarter Ended September 30	Quarter Ended June 30	Quarter Ended March 31
Operating revenues	$370	$390	$357	$317
Operating income	13	14	5	8
Net income attributable to Regency Energy Partners LP	13	30	15	14
Earnings per common units:				
Basic net income per common unit	0.06	0.18	0.08	0.08
Diluted net income per common unit	0.06	0.09	0.07	0.07