Regency Energy Partners LP
Form 10-K
February 18, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

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: 000-51757

REGENCY ENERGY PARTNERS LP

(Exact name of registrant as specified in its charter)

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

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 x 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 x

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

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 x No ¨

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

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

As of June 30, 2010, the aggregate market value of the registrant s common units held by non-affiliates of the registrant was $2,255,285,940 based on the closing sale price on such date as reported on the NASDAQ Global Select Market.

There were 137,295,308 common units outstanding as of February 10, 2011.

DOCUMENTS INCORPORATED BY REFERENCE

None

REGENCY ENERGY PARTNERS LP

ANNUAL REPORT ON FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2010

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Introductory Statement

References in this report to the Partnership, we, our, us and similar terms, when used in an historical context, refer to Regency Energy Partne LP and its subsidiaries. When used in the present tense or prospectively, these terms refer to the Partnership and its subsidiaries. We use the following definitions in this annual report on Form 10-K:

Name	Definition or Description
Alinda Investors	Alinda Gas Pipelines I, L.P. and Alinda Gas Pipelines II, L.P.
ACESA	The American Clean Energy and Security Act of 2009
ASC	ASC Hugoton LLC
Bbls/d	Barrels per day
Bcf/d	One billion cubic feet per day
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
CDM	CDM Resource Management LLC
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFTC	Commodity Futures Trading Commission
DHS	Department of Homeland Security
DOT	U.S. Department of Transportation
EFS Haynesville	EFS Haynesville, LLC, a 100 percent owned subsidiary of GECC
EIA	Energy Information Administration
EnergyOne	FrontStreet EnergyOne LLC
El Paso	El Paso Field Services, LP
EPA	Environmental Protection Agency
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
FrontStreet	FrontStreet Hugoton LLC
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 LP and Regency LP
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
HM Capital	HM Capital Partners LLC
HPC	RIGS Haynesville Partnership Co., a general partnership, and its 100 percent owned subsidiary, Regency Intrastate Gas LP
ICA	Interstate Commerce Act
IDRs	Incentive Distribution Rights
IPO	Initial Public Offering of Securities
IRS	Internal Revenue Service
ISDA	International Swap Dealers Association
KMP	Kinder Morgan Energy Partners, L.P.

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Name	Definition or Description
LIBOR	London Interbank Offered Rate
LTIP	Long-Term Incentive Plan
MEP	Midcontinent Express Pipeline LLC
MLP	Master Limited Partnership
MMbtu	One million BTUs
MMbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
MQD	Minimum Quarterly Distribution
Nasdaq	Nasdaq Stock Market, LLC
Nexus	Nexus Gas Holdings, LLC
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
OSHA	Occupational Safety and Health Act
Partnership	Regency Energy Partners LP
PTO	Paid time off
Pueblo	Pueblo Midstream Gas Corporation, a wholly-owned subsidiary of the Partnership
RCRA	Resource Conservation and Recovery Act
Regency HIG	Regency Haynesville Intrastate Gas LLC, a wholly owned subsidiary of the Partnership
Regency Midcon	Regency Midcontinent Express LLC, a 100 percent owned subsidiary of the Partnership
RFS	Regency Field Services LLC, a wholly-owned subsidiary of the Partnership
RGS	Regency Gas Services LP, a wholly-owned subsidiary of the Partnership
RIG	Regency Intrastate Gas LP
RIGS	Regency Intrastate Gas System
SCADA	System Control and Data Acquisition
SEC	Securities and Exchange Commission
Series A Preferred Units	Series A convertible redeemable preferred units
Services Co.	ETE Services Company, LLC
TCEQ	Texas Commission on Environmental Quality
Tcf	One trillion cubic feet
Tcf/d	One trillion cubic feet per day
TRRC	Texas Railroad Commission
WTI	West Texas Intermediate Crude
Zephyr	Zephyr Gas Services, LP, or Zephyr Gas Services LLC after September 1, 2010

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-
Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we cannot give

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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 natural gas liquids;
- 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 our customers of our contract compression and contract treating businesses;
- 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;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- regulation of transportation rates on our natural gas pipelines;
- 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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Item 1. Business

OVERVIEW

We are a growth-oriented publicly-traded Delaware limited partnership formed in 2005 engaged in the gathering, treating, processing, compression and transportation of natural gas and NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Haynesville, Eagle Ford, Barnett, Fayetteville and Marcellus shales as well as the Permian Delaware basin. Our assets are primarily located in Louisiana, Texas, Arkansas, Pennsylvania, Mississippi, Alabama 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 and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems.

Transportation. We own a 49.99 percent general partner interest in HPC, which owns RIGS, a pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets through the 450-mile intrastate natural gas pipeline. We also own a 49.9 percent 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.

Contract Compression. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems.

Contract Treating. 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, to natural gas producers and midstream pipeline companies.

Corporate and Others. Our Corporate and Others segment comprises a small regulated pipeline and our corporate offices.

See Note 16 to our consolidated financial statements for additional financial information about our segments.

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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, 2010.

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

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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 small diameter pipelines and, if necessary, a compression system which together collects natural gas from points near producing wells and transports it to processing or treating plants or larger diameter pipelines for further transportation.

Compression. Ideally-designed gathering systems are operated at pressures that maximize the total throughput volumes from all connected wells. Natural gas compression is a mechanical process in which a volume of 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 to be transported to market. Since natural gas wells produce gas at progressively lower field pressures as they age, this raw natural gas must be compressed to deliver the remaining production at higher pressures in the existing connected gathering system. This field compression is typically used to lower the suction (entry) pressure, while maintaining or increasing the discharge (exit) pressure to the gathering system which allows the well production to flow at a lower receipt pressure while providing sufficient pressure to deliver gas into a higher pressure downstream pipeline.

Dehydration. Dehydration removes water from the natural gas stream, which can form ice when combined with natural gas and cause corrosion when combined with carbon dioxide or hydrogen sulfide.

Processing. Natural gas processing involves the separation of natural gas into pipeline quality natural gas and a mixed NGL stream. The principal component of natural gas is methane, but most natural gas also contains varying amounts of heavier hydrocarbon components, or NGLs. Natural gas is described as lean or rich depending on its content of NGLs. Most natural gas produced by a well is not suitable for long-haul pipeline transportation or commercial use because it contains NGLs and impurities. Removal and separation of individual hydrocarbons by processing is possible because of differences in weight, boiling point, vapor pressure and other physical characteristics.

Amine Treating. The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to absorb these impurities from the gas. After mixing in the contact vessel, 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. We do not own or operate any NGL fractionation facilities.

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.

INDUSTRY OUTLOOK

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

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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 delivery 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, please 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.

The following table sets forth information regarding our gathering systems and processing plants as of December 31, 2010.

Region	Pipeline Length (Miles)	Plants	Compression (Horsepower)
North Louisiana	442	4	55,489
South Texas	541	2	48,132
West Texas	806	1	48,574
Mid-Continent	3,470	1	40,576
Total	5,259	8	192,771

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 and a conditioning plant located in Webster Parish.

Through the gathering and processing systems described above and their interconnections with HPC s pipeline system in north Louisiana described in 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 primarily from natural gas wells located in a mature basin that generally have long lives and predictable gas flow rates. The emerging Eagle Ford shale formation lies directly under our existing south Texas gathering system infrastructure.

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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. An additional 55 MMcf/d amine treating unit is currently inactive.

We own a 60 percent interest in a joint venture 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. We operate this plant and the pipeline for the joint venture while our joint venture partner operates a lean gas gathering system in the Edwards Lime natural gas trend that delivers to this system.

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 major 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. Natural gas exploration and production drilling in this area has primarily targeted productive zones in the Permian Delaware basin and Devonian basin. These basins are mature basins with wells that generally have long lives and predictable flow rates.

We offer producers 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. This plant was constructed in 1965, and, due to recent upgrades to state-of-the-art cryogenic processing capabilities, is a highly efficient natural gas processing plant. 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.

Mid-Continent Region. Our mid-continent region includes natural gas gathering systems located primarily in Kansas and Oklahoma. 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 1,875 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.

Our mid-continent systems are located in two of the largest and most prolific 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.

TRANSPORTATION OPERATIONS

We own a 49.99 percent general partner interest in HPC, which owns RIGS, a pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets through the 450-mile intrastate natural gas pipeline. We also own a 49.9 percent interest in MEP, a joint venture entity operated by an affiliate of KMP and owning 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.

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CONTRACT COMPRESSION OPERATIONS

The natural gas contract compression segment services include designing, sourcing, owning, insuring, installing, operating, servicing, repairing and maintaining compressors and related equipment for which we guarantee our customers 98 percent mechanical availability for land installations and 96 percent 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, natural gas lift for crude oil production 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 and Pennsylvania.

CONTRACT TREATING OPERATIONS

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, to natural gas producers and midstream pipeline companies. Our contract treating operations are primarily located in Texas, Louisiana and Arkansas.

CORPORATE AND OTHERS OPERATIONS

Our Corporate and Others segment comprises a small interstate natural gas pipeline and our corporate offices. The interstate natural gas pipeline consists of 10 miles of pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

OUR CONTRACTS

The table below provides the margin by contract types in percentages for the years ended December 31, 2010 and 2009.

Margin by Product	2010	2009
Net Fee	76%	73%
NGLs	13	18
Gas	5	4
Condensate	6	5
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, 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 and resell the natural gas to other market participants.

Transportation Contracts. We own a 49.99 percent general partner interest in HPC and a 49.9 percent interest in MEP. Both 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.

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 are also 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 and Enbridge Inc.;

South Texas: Enterprise Products Partners LP and DCP Midstream Partners, L.P, KMP, ETP and Copano Energy, L.L.C;

West Texas: Southern Union Gas Services and Enterprise Products Partners LP and Targa Resources Partners L.P.; and

Mid-Continent: DCP Midstream Partners, L.P., ONEOK Energy Marketing and Trading, L.P. and Penn Virginia Corporation.

Transportation. Competitors in natural gas transportation differentiate themselves by 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 and new entrants in north Louisiana such as ETP and Enterprise Products Partners LP.

We also own a 49.9 percent interest in MEP, which owns the approximate 500-mile Midcontinent Express natural gas pipeline system, and we account for our investment under the equity method of accounting. An affiliate of KMP owns a 50 percent interest in MEP and acts as the operator of MEP. Capacity on the MEP pipeline system is 99 percent 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. Competitors to MEP include Gulf Crossing Pipeline, Centerpoint Energy Gas Transmission and Natural Gas Pipeline Co. of America.

Contract Compression. 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 has proven 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

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natural gas contract compression services 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 contract compression business, based on horsepower, are Exterran Holdings, Inc., Compressor Systems, Inc., USA Compression, Valerus Compression Services LP, and J-W Operating Company.

Contract Treating. 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 Kinder Morgan Treating LP, Valerus Compression Services LP, TransTex Gas Services, LP, Cardinal Midstream LLC, SouthTex Treaters, Interstate Treating Inc., Exterran Holdings, Inc. and Thomas Russell Co.

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 natural gas liquids) 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 both the NGL 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 natural gas liquids 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 also hedge this commodity price risk by entering into a series of swap contracts for individual NGLs, natural gas and WTI. Our hedging position and needs to supplement or modify our position are closely monitored by the Risk Management Committee of the Board of Directors. Please 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.

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, terms and conditions of service are subject to the jurisdiction of FERC, including its non-discrimination requirements.

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Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of such fair and equitable rates are subject to refund with interest. NGPA Section 311 rates deemed fair and equitable by FERC are generally analogous to the cost-based rates that FERC deems just and reasonable for interstate pipelines under the NGA. FERC has substantial enforcement authority to impose administrative, civil and criminal penalties, and to order the disgorgement of unjust profits for non-compliance.

In January 2010, RIG filed a petition with FERC to increase its maximum rates for Section 311 transportation services to recover the costs of operating RIGS, including HPC s expansion projects. On June 24, 2010, FERC approved a settlement establishing RIGS maximum rates for the period commencing February 1, 2010. Under the settlement, which applies to RIGS interstate shippers, RIGS was not required to make any refunds to shippers, and was authorized to implement maximum rates that are higher than RIGS previously-effective maximum rates. In addition, RIGS was authorized to increase its maximum fuel retention rates upon the future installation of additional compression on RIGS. Consistent with FERC policy, RIGS is required to justify its current rates or propose new rates every five years, which must be done next on or before February 1, 2015.

On December 16, 2010, FERC issued its Order on Rehearing of Order No. 735. Order No. 735, which was initially issued on July 21, 2010, revises the contract reporting requirements for intrastate natural gas pipelines that provide interstate transportation services pursuant to Section 311 of the NGPA. The new reporting requirements, which were effective January 1, 2011, require the public disclosure of the primary commercial terms of HPC s contracts, including shipper name, contract length, rates charged and points of receipt and delivery. Such regulations increase administration costs for HPC and require the public disclosure of commercial information that was previously not public for intrastate pipelines. Since the new regulations are required of all intrastate pipelines providing Section 311 service, including our competitors, we do not believe the new regulations place RIGS at a disadvantage vis-à-vis its competitors.

FERC is continually proposing and implementing new rules and regulations affecting Section 311 transportation. Newly adopted transparency regulations require certain major non-interstate pipelines, including gathering pipelines, to post on their internet websites receipt and delivery point capacities and scheduled flow information on a daily basis. These regulations are intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve FERC s ability to assess market forces and detect market manipulation. Although these regulations are currently subject to petitions for review before the United States Court of Appeals for the Fifth Circuit, major non-interstate pipelines were required to comply with these requirements as of October 1, 2010. Currently, these newly adopted regulations apply to RIGS, but they may apply to other Regency facilities if they meet the threshold requirements in the future.

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. FERC s interstate pipeline rules prohibit shippers on interstate pipelines from buying gas from a party at one point, transporting that gas using its interstate pipeline capacity, and re-selling the same quantity of gas to the same party at a different point (an illegal buy-sell transaction). The intrastate pipeline market has not been subject to such rules in the past and the FERC, through the notice of inquiry, has asked market participants to comment on whether the rules should apply to shippers on Section 311 pipelines. The notice of inquiry also asks commenters to indicate whether some form of capacity release requirements should be imposed on intrastate pipelines providing firm Section 311 transportation service. We cannot predict the outcome of this notice of inquiry, but it could lead to a proposed rulemaking that would impose 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, and amounts collected in excess of just and reasonable rates are subject

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to refund with interest. Gulf States holds FERC-approved tariffs setting forth cost-based rates, terms and conditions for services to shippers wishing to take interstate transportation service. We also hold a 49.9 percent interest in MEP, a joint venture entity owning a 500-mile interstate pipeline system (Midcontinent Express Pipeline), which is an NGA-jurisdictional interstate pipeline 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.

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. In the certificate order, FERC also approved cost-based recourse rates available to prospective shippers as an alternative to negotiated rates.

Any failure to comply with the laws and regulations governing interstate transmission service could result in the imposition of administrative, civil and criminal penalties.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC 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, so 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.

With the passage of the Energy Policy Act of 2005, FERC has expanded its oversight to energy market participants, including gathering pipelines, to increase transparency in interstate markets. Newly-adopted transparency regulations require certain non-interstate pipelines, including gathering pipelines, to post on their Internet websites receipt and delivery point capacities and scheduled flow information on a daily basis. Although these regulations are currently subject to petitions for review before the United States Court of Appeals for the Fifth Circuit, these new requirements and future proposed regulations could impose increased costs and administrative burdens on our gathering companies.

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

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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.

Natural gas gathering may receive greater regulatory scrutiny at the state level now that the FERC has allowed a number of interstate pipeline transmission companies to transfer formerly jurisdictional assets to gathering companies.

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 the industry 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.

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. FERC has also imposed new rules requiring wholesale purchasers and sellers of natural gas to report certain aggregated annual volume and other information beginning in 2009.

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 the 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 Liquids. 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.

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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 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 $1,000,000 per day per violation, 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.

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 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 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, 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

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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 that may fall within that definition, and certain state law analogs to CERCLA, including the Texas Solid Waste Disposal Act, do not contain a similar exclusion for petroleum. 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 certain 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

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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.

On October 20, 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, 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.

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. While we have no reason to believe that we operate in any area that is 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, could cause us to incur additional costs or 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 recently 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 that have yet to be developed. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce 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, 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 8, 2010, the EPA revised its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. If the proposed rule is finalized as proposed, reporting of greenhouse gas emissions from such facilities, including many of our facilities, will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

In June 2009, the United States House of Representatives passed ACESA, which would establish an economy-wide cap on emissions of greenhouse gases in the United States and would require most sources of greenhouse gas emissions to obtain and hold allowances corresponding to their annual emissions of greenhouse gases. By steadily reducing the number of available allowances over time, ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Legislation to reduce emissions of greenhouse gases by comparable amounts is currently pending in the United States Senate, and 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.

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 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.

The DOT has enacted new regulations as directed by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The proposed rules require operators of hazardous liquids pipelines, gas pipelines and LNG facilities with at least one control room to develop and implement and submit written control room management procedures. Compliance is required by August 1, 2011 and implementation is required by February 1, 2012, although the DOT has sought comments on expediting implementation to August 1, 2011. Implementation of the control room management procedures will result in additional costs for us.

New TCEQ Rule. On January 26, 2011, the TCEQ adopted a new Section 352 Oil and Gas 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, under the PBR, the construction of new facilities near existing facilities could cause the existing and new facilities to be subject to increased requirements, including the installation of additional emissions control equipment, which would increase the costs of new projects and increase capital expenditures in the Barnett Shale in Texas. Currently, our facilities located in the Barnett Shale are part of our Compressor Segment, and most compliance costs resulting from the PBR will be borne by our customers.

EMPLOYEES

As of December 31, 2010, our General Partner employed 793 employees, of whom 583 were field operating employees and 210 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.

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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 the risks we face and other factors currently considered immaterial or unknown to us 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;
- fluctuation in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the cost of acquisition, 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. In the past, the prices of natural gas and crude oil have been extremely volatile, and this volatility could continue. Volatility in crude oil and natural gas 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 oil, natural gas and NGLs, which fluctuates with changes in market and economic conditions and other factors, including:

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

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

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

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

The level of natural gas drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is natural gas prices. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and

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processing facilities and pipeline transportation systems, which would lead to reduced utilization of these assets. Recently 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, which have become more constrained in this past year, 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 or natural gas lift for crude oil 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.

Many of our customers drilling activity levels and spending for transportation on our pipeline system 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 pipeline system. 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 own an equity interest in HPC and in MEP, but we do not exercise control over either of them.

We own a 49.99 percent general partner interest in HPC, and we have the right to appoint two members of the four member management committee. We also have the right to vote the 0.01 percent ownership interest retained by GE EFS. Each member has a vote equal to the sharing ratio of the partner that appointed such member. Accordingly, we do not exercise control over HPC. In addition, HPC s partnership agreement contains standard supermajority voting provisions and also requires that the following actions, among other things, be approved by at least 75 percent of the members of the management committee: a merger or consolidation of the joint venture, the sale of all or substantially all of the assets of the joint venture, a determination to raise additional capital, determining the amount of available cash, causing the joint venture to terminate the master services agreement, approval of any budget and entry into material contracts.

We have a 49.9 percent non-operated ownership interest in MEP, and we have the right to appoint one member to the three-member board of directors. An affiliate of KMP owns a 50 percent interest in MEP and thus has the sole right to appoint the officers of MEP and to make other operating decisions. Accordingly, we do not exercise control over MEP. In addition, MEP s limited liability company agreement provides that 65 percent of the membership interest constitutes a quorum. Most matters require a majority vote, but the following actions, among other things, require the approval of at least 80 percent of the membership interest: the sale of any assets outside the ordinary course of business or with a fair market value in excess of $5,000,000, a merger, consolidation or liquidation, modifying or terminating any agreement with a member, issuing, selling or repurchasing membership interests, incurring or refinancing indebtedness in excess of $25,000,000 and filing or settling any litigation or arbitration that involves claims or settlements in excess of $5,000,000.

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

Both HPC and MEP 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.

Our contract compression 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., an affiliate 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.

Our contract treating 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 segment s 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 contract treating s 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 segment 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 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 downward movements in commodity prices. As a result of the volatility of commodity prices and interest rates, we have executed swap contracts settled against ethane, propane, normal butane, natural gas, natural gasoline and west Texas intermediate crude market prices and interest rates. 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, please 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 recent 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.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although 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 and any new regulations could significantly increase the cost of derivative contracts (including

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through requirements to post collateral, which could adversely affect our available liquidity), 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.

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 s expansion project 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, 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.

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, 2010 was 26 percent. We will be prohibited from making cash distributions during 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

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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.

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. 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 businesses 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 administrative, civil and/or criminal penalties, or both, as well as increased operational requirements or prohibitions.

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As limited partnership entities, neither we nor our regulated 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 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 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 new rules requiring increased reporting by purchasers and sellers of natural gas, intrastate pipelines and gathering systems of certain information, and in 2009, FERC issued a notice of proposed rulemaking seeking comments on proposed increased transactional reporting requirements for intrastate pipelines. We cannot predict the outcome of the rulemaking 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

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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. In addition, TCEQ has proposed a new Section 352 Oil and Gas Permit by Rule (PBR), which is applicable to gas pipeline facilities and provides an authorization for activities that produce more than a de minimis level of emissions, but too little emissions for other permitting options, if the conditions of PBR are met. If adopted, our compliance with the conditions in the proposed PBR may result in substantial increases in our capital expenditures and operating costs.

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, laws 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 the 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 pipeline companies that have greater financial resources

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and access to supplies of natural gas 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, 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 revenue 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 NGLs, including:

- damage to our gathering and processing facilities, pipelines, related equipment and surrounding properties caused by tornadoes, floods, hurricanes, fires and other natural disasters and acts of terrorism;

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- 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 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 dewpoint, 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;

- 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 $241,000 in 2011 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.

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In the last Congress, the U.S. House of Representatives passed legislation that would increase penalties for pipeline safety violations, reduce reporting periods and provide for review and possibly revocation of exemptions for gathering systems from regulation by the DOT s Pipeline and Hazardous Materials Safety Administration (PHMSA), among other matters. The Senate did not act on this bill in the last session of Congress. In addition, members of Congress have introduced other legislation on pipeline safety and the DOT has announced a review of its safety rules and its intention to strengthen those rules. We anticipate that new legislation will be proposed in the current session of Congress. In addition, PHMSA and the National Transportation Safety Board are considering actions and advisories as a result of some high profile pipeline accidents. We cannot predict the outcome of these legislative and regulatory initiatives, but legislative and regulatory changes could have a material effect on our operations and could subject us to more comprehensive and more stringent safety regulation and greater penalties for violations of safety rules.

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 for specified periods of time. 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 supplies to our existing gathering lines 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.

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 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.

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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.

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 recently 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 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 that have yet to be developed. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce 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, 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 8, 2010, the EPA revised its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. If the proposed rule is finalized as proposed, reporting of greenhouse gas emissions from such facilities, including many of our facilities, will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

In June 2009, the United States House of Representatives passed ACESA which would establish an economy-wide cap on emissions of greenhouse gases in the United States and would require most sources of greenhouse gas emissions to obtain and hold allowances corresponding to their annual emissions of greenhouse gases. By steadily reducing the number of available allowances over time, ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Legislation to reduce emissions of greenhouse gases by comparable amounts is currently pending in the United States Senate, and 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 preferred units.

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 percent 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. 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 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 our business. 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 is 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 our operations 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 no assurance can be given that we will maintain our current credit ratings.

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

ETE owns 26,266,791 of our common units and an affiliate of GE owns 15,277,106 of our common units. We have agreed to provide to each of ETE and GE s affiliate the right to register for resale their common units. We filed a registration statement relating to the resale of GE s common units that became effective on October 15, 2010. 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, 2010, our consolidated balance sheet reflected $789,789,000 of goodwill and $770,155,000 of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that 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 were 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.

Hydraulic fracturing is a process used by oil and gas exploration and production operators in the completion of certain oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and, to a lesser extent, oil production. Due to concerns that hydraulic fracturing may adversely affect drinking water supplies, the EPA recently announced a plan to conduct a comprehensive research study to investigate the potential adverse impact that hydraulic fracturing may have on water quality and public health. The initial study results are expected to be available in late 2012. Additionally, legislation was introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to regulate hydraulic fracturing and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. If enacted, such a provision could require hydraulic fracturing activities to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping requirements and meet plugging and abandonment requirements. Unrelated oil spill legislation considered by the U.S. Senate in the aftermath of the April 2010 Macondo well release in the Gulf of Mexico contained a provision that would require natural gas drillers to disclose the chemicals they pump into the ground as part of the hydraulic fracturing process. Aside from these federal initiatives, several states have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Adoption of legislation or of any implementing regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas that we gather, process and transport.

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

Some portions of our assets, including 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 the general partner of ETP. This may result in conflicts of interest.

ETE owns our General Partner and as a result controls us. ETE also owns the general partner of Energy Transfer Partners, L.P., or ETP, a publicly-traded partnership with which we compete in the natural gas gathering, processing and transportation 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, 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 we make to the parent company of our General Partner;

- ETE and ETP and their affiliates may engage in substantial competition with us;

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- Neither our partnership agreement nor any other agreement requires ETE or its affiliates, including ETP, to pursue a business strategy that favors us. The directors and officers of the general partners of ETE and ETP 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 and ETP 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 and ETP 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., 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, 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

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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 the provisions 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 $^{2}/_{3}$ percent of all outstanding units voting together as a single class is required to remove the General Partner. As of February 10, 2011, affiliates of our General Partner owned 19.1 percent of the total of our common units.

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

Unitholders voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20 percent 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 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

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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 percent 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 10, 2011, affiliates of our General Partner owned 19.1 percent of the total of our 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 or MEP 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 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.

Additionally, the ability of our 49.99 percent owned unconsolidated subsidiary, HPC, and our 49.9 percent owned unconsolidated subsidiary, MEP, 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. Specifically, the management committee of HPC is entitled to determine the amount of cash that is distributed to its partners, which includes a determination of what cash reserves are necessary for the operation of the business of HPC. The management committee consists of four members. Each partner of HPC has appointed one management committee member, and each member has a vote equal to the sharing ratio of the partner that appointed such member. Cash distributions to us by HPC require the approval of at least 75 percent of the votes entitled to be cast by the management committee members. Additionally, under MEP s limited liability company agreement, MEP is required to make monthly distributions to its members of all available cash. The amount of available cash is determined by MEP s board of directors which consists of three members, one appointed by each member of MEP. Decisions relating to available cash require the approval of directors appointed by members collectively holding 65 percent or more of the membership interests at the time such action is taken. Accordingly, we are not able to control the amounts of cash that HPC or MEP 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 percent, 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

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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.

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

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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 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

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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 percent 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 percent or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50 percent 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.

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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, Colorado 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 RIG and MEP), 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 and in our corporate and others 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, Texas and Arkansas. 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, please 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 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.

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We maintain insurance policies with insurers in amounts and with coverages and deductibles that we, with the advice of our insurance advisors 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 to our consolidated financial statements.

Item 4. (Removed and Reserved)

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Part II

Item 5. Market for Registrant s Common Equity, 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. Our common units are listed on the NASDAQ Global Select Market under the symbol RGNC. As of February 10, 2011, the number of holders of record of common units was 37, with 110,377,542 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 NASDAQ Global Select Market, and the cash distributions declared per common unit.

Period	Price Ranges High	Price Ranges Low	Cash Distributions (per unit)
2010			
First Quarter(1)	23.19	20.00	0.4450
Second Quarter(1)	24.57	20.43	0.4450
Third Quarter(1)	26.45	23.54	0.4450
Fourth Quarter(1)	27.26	24.33	0.4450
2009			
First Quarter	12.89	8.08	0.4450
Second Quarter	14.68	11.00	0.4450
Third Quarter(1)	19.65	14.07	0.4450
Fourth Quarter(1)	21.00	18.56	0.4450

(1) Excludes the Series A Preferred Units which began receiving fixed quarterly cash distributions of $0.445 beginning with the quarter ending March 31, 2010.

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.

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In addition to distributions on its two percent General Partner interest, our General Partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in the following table.

	Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distributions Unitholders	General Partner	Incentive Distribution Rights
Minimum Quarterly Distribution	$0.35	98	2	
First Target Distribution	up to $0.4025	98	2	
Second Target Distribution	above $0.4025 up to $0.4375	85	2	13
Third Target Distribution	above $0.4375 up to $0.5250	75	2	23
Thereafter	above $0.5250	50	2	48

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.

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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 Recent Developments for a discussion of why our results may not be comparable, either from period to period or going forward.

	Successor	Predecessor				
	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	Year Ended December 31, 2007	Year Ended December 31, 2006
	(in thousands except per unit data)	(in thousands except per unit data)				
Statement of Operations Data:						
Total revenues	$ 716,613	$ 505,050	$ 1,043,277	$ 1,785,263	$ 1,138,205	$ 862,216
Total operating costs and expense	702,054	484,919	816,703	1,635,520	1,084,723	826,435
Operating income	14,559	20,131	226,574	149,743	53,482	35,781
Other income and deductions:						
Income from unconsolidated subsidiaries	53,493	15,872	7,886			
Interest expense, net	(48,251)	(34,541)	(77,665)	(62,940)	(51,851)	(37,182)
Loss on debt refinancing, net	(15,748)	(1,780)			(21,200)	(10,761)
Other income and deductions, net	(8,229)	(3,897)	(15,132)	328	1,249	839
(Loss) income from continuing operations before income taxes	(4,176)	(4,215)	141,663	87,131	(18,320)	(11,323)
Income tax expense (benefit)	552	404	(1,095)	(266)	931	
(Loss) income from continuing operations	$ (4,728)	$ (4,619)	$ 142,758	$ 87,397	$ (19,251)	$ (11,323)
Discontinued operations						
Net (loss) income from operations of east Texas assets	(1,244)	(327)	(2,269)	13,931	5,720	4,079
Net (loss) income	(5,972)	(4,946)	140,489	101,328	(13,531)	(7,244)
Net income attributable to noncontrolling interest	(156)	(406)	(91)	(312)	(305)	
Net (loss) income attributable to Regency Energy Partners LP	$ (6,128)	$ (5,352)	$ 140,398	$ 101,016	$ (13,836)	$ (7,244)
Less:						
Net income through January 31, 2006						1,564
Net (loss) income for partners	$ (6,128)	$ (5,352)	$ 140,398	$ 101,016	$ (13,836)	$ (8,808)
Amounts attributable to Series A convertible redeemable preferred units	4,651	3,336	3,995			
General partner s interest, including IDRs	2,800	662	5,252	4,303	(366)	(164)
Amount allocated to non-vested common units		(79)	965	869	(103)	(110)
Beneficial conversion feature for Class C common units					1,385	3,587
Beneficial conversion feature for Class D common units			820	7,199		
Amount allocated to Class B common units						(886)
Amount allocated to Class E common units					5,792	

Limited partners interest in net (loss) income	$	(13,579)	$	(9,271)	$	129,366	$	88,645	$	(20,544)	$	(11,235)
Basic and diluted (loss) income from continuing operations per unit:												
Basic (loss) income from continuing operations per common and subordinated unit	$	(0.09)	$	(0.10)	$	1.63	$	1.14	$	(0.51)	$	(0.42)

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	Successor	Predecessor				
	Period from Acquisition (May 26, 2010) to December 31, 2010 (in thousands except per unit data)	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006
		(in thousands except per unit data)				
Diluted (loss) income from continuing operations per common and subordinated unit	$ (0.09)	$ (0.10)	$ 1.63	$ 1.10	$ (0.51)	$ (0.42)
Cash distributions declared per common and subordinated unit	0.89	0.89	1.78	1.71	1.52	0.94
Basic and diluted (loss) income on discontinued operations per unit	$ (0.01)	$	$ (0.03)	$ 0.21	$ 0.11	$ 0.11
Basic and diluted net income (loss) per unit:						
Basic net (loss) income per common and subordinated unit	$ (0.10)	$ (0.10)	$ 1.61	$ 1.34	$ (0.40)	$ (0.29)
Diluted net (loss) income per common and subordinated unit	(0.10)	(0.10)	1.60	1.28	(0.40)	(0.29)
Basic and diluted net loss per Class B common unit						(0.17)
Cash distributions declared per Class B common unit						
Income per Class C common unit due to beneficial conversion feature					0.48	1.26
Cash distributions declared per Class C common unit						
Income per Class D common unit due to beneficial conversion feature			0.11	0.99		
Cash distributions declared per Class D common unit						
Basic and diluted net income per Class E common units					1.23	
Cash distributions per Class E common unit					2.06	

	Successor	Predecessor			
	December 31, 2010 (in thousands)	December 31, 2009	December 31, 2008	December 31, 2007	December 31, 2006
			(in thousands)		
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 1,660,218	$ 1,456,435	$ 1,703,554	$ 913,109	$ 734,034
Total assets	4,770,204	2,533,414	2,458,639	1,278,410	1,013,085
Long-term debt (long-term portion only)	1,141,061	1,014,299	1,126,229	481,500	664,700
Series A convertible redeemable preferred units	70,943	51,711			
Partners capital	3,294,402	1,243,010	1,099,413	568,186	212,657

	Successor	Predecessor				
	Period from Acquisition (May 26, 2010) to December 31, 2010 (in thousands)	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006
				(in thousands)		
Cash Flow Data:						
Net cash flows provided by (used in):						
Operating activities	$ 79,786	$ 89,421	$ 143,960	$ 181,298	$ 79,529	$ 44,156

Investing activities	(296,429)	(148,450)	(156,165)	(948,629)	(157,933)	(223,650)
Financing activities	203,059	72,186	21,433	734,959	99,443	184,947
Other Financial Data:						
Adjusted total segment margin(1)	$ 235,319	$ 154,422	$ 361,182	$ 402,143	$ 200,970	$ 133,770
Adjusted EBITDA(1)	218,162	108,794	210,994	259,327	157,769	95,717
Maintenance capital expenditures	6,881	7,880	20,170	18,247	8,764	16,433

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

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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, 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 expenses;
- loss (gain) on asset sales, net;
- loss on debt refinancing;
- other non-cash (income) expense, net; and
- the Partnership s interest in adjusted EBITDA from unconsolidated subsidiaries less income from unconsolidated subsidiaries.

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 methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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. Our EBITDA and adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate adjusted EBITDA in the same manner.

EBITDA and adjusted EBITDA do not include interest expense, income taxes 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 total segment margin as the total of segment margin of our five segments, less intersegment eliminations. We define adjusted total segment margin as total segment margin adjusted for non-cash (gains) losses from commodity derivatives.

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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 amounts in the same manner.

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	Successor	Predecessor				
	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	Year Ended December 31, 2007	Year Ended December 31, 2006
	(in thousands)			(in thousands)		
Reconciliation of Adjusted EBITDA to net cash flows provided by operating activities and to net (loss) income						
Net cash flows provided by operating activities	$ 79,786	$ 89,421	$ 143,960	$ 181,298	$ 79,529	$ 44,156
Add (deduct):						
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	(79,323)	(49,363)	(116,307)	(105,324)	(57,069)	(39,287)
Write-off of debt issuance costs and bond premium	1,422	(1,780)			(5,078)	(10,761)
Amortization of excess fair value of unconsolidated subsidiaries	(3,410)					
Income from unconsolidated subsidiaries	56,903	15,872	(7,886)		43	532
Derivative valuation change	(33,189)	(12,004)	(5,163)	14,700	(14,667)	2,262
(Loss) gain on assets sales, net	(268)	(303)	133,284	(472)	(1,522)	
Unit-based compensation expenses	(1,827)	(12,070)	(6,008)	(4,306)	(15,534)	(2,906)
Gain on insurance settlements				3,282		
Trade accounts receivable, accrued revenues and related party receivables	401	11,272	(10,727)	(18,648)	28,789	5,506
Other current assets	107	(2,516)	(10,471)	6,615	1,394	(104)
Trade accounts payable, accrued cost of gas and liquids, related party payables, and deferred revenues	15,302	(8,649)	3,762	40,772	(30,089)	1,359
Other current liabilities	12,853	(22,614)	6,726	(12,749)	149	(3,640)
Proceeds from early termination of interest rate swap						(4,940)
Amount of swap termination proceeds reclassified into earnings					1,078	3,862
Distributions received from unconsolidated subsidiaries	(56,903)	(12,446)	7,886			
Other assets and liabilities	2,174	234	1,433	(3,840)	(554)	(3,283)
Net (loss) income	(5,972)	(4,946)	140,489	101,328	(13,531)	(7,244)
Add (deduct):						
Interest expense, net	48,292	34,679	77,996	63,243	52,016	37,182
Depreciation and amortization	76,641	46,084	109,893	102,566	55,074	39,654
Income tax expense (benefit)	552	404	(1,095)	(266)	931	
EBITDA	119,513	76,221	327,283	266,871	94,490	69,592
Add (deduct):						
Non-cash loss (gain) from commodity and embedded derivatives	31,424	11,189	5,163	(14,708)	11,500	(6,158)
Non-cash unit-based compensation	1,802	11,925	5,834	4,318	15,535	2,906
Loss (gain) on assets sales, net	288	303	(133,284)	472	1,522	
Income from unconsolidated subsidiaries	(53,493)	(15,872)	(7,886)			
Partnership s ownership interest in HPC s adjusted EBITDA	45,830	21,184	11,398			
Partnership s ownership interest in MEP s adjusted EBITDA	55,682					
Loss on debt refinancing, net	15,748	1,780			21,200	10,761
Other expense, net	1,368	2,064	2,486	2,374	13,522	18,616
Adjusted EBITDA	$ 218,162	$ 108,794	$ 210,994	$ 259,327	$ 157,769	$ 95,717

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	Successor		Predecessor			
	Period from Acquisition (May 26, 2010) to December 31, 2010 (in thousands)	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008 (in thousands)	Year Ended December 31, 2007	Year Ended December 31, 2006
Reconciliation of Adjusted total segment margin to net (loss) income						
Net (loss) income	$ (5,972)	$ (4,946)	$ 140,489	$ 101,328	$ (13,531)	$ (7,244)
Add (deduct):						
Operation and maintenance	77,808	47,842	117,080	119,715	47,385	29,010
General and administrative	43,739	37,212	57,863	51,323	39,713	22,806
Loss (gain) on assets sales, net	213	303	(133,282)	457	1,522	
Management services termination fee				3,888		12,542
Transaction expenses				1,620	420	2,041
Depreciation and amortization	75,967	41,784	100,098	93,393	46,362	34,090
Income from unconsolidated subsidiaries	(53,493)	(15,872)	(7,886)			
Interest expense, net	48,251	34,541	77,665	62,940	51,851	37,182
Loss on debt refinancing, net	15,748	1,780			21,200	10,761
Other income and deductions, net	8,229	3,897	15,132	(328)	(1,249)	(839)
Income tax (benefit) expense	552	404	(1,095)	(266)	931	
Discontinued operations	1,244	327	2,269	(13,931)	(5,720)	(4,079)
Total segment margin	212,286	147,272	368,333	420,139	188,884	136,270
Add (deduct):						
Non-cash loss (gain) from commodity derivatives	23,033	7,150	(7,151)	(17,996)	9,027	(6,158)
Non-cash put option expiration					3,059	3,658
Adjusted total segment margin	$ 235,319	$ 154,422	$ 361,182	$ 402,143	$ 200,970	$ 133,770

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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, treating, processing, compression and transportation of natural gas and NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Haynesville, Eagle Ford, Barnett, Fayetteville and Marcellus shales as well as the Permian Delaware basin. Our assets are primarily located in Louisiana, Texas, Arkansas, Pennsylvania, Mississippi, Alabama 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 and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems.

Transportation. We own a 49.99 percent general partner interest in HPC, which owns RIGS, a pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets through the 450-mile intrastate natural gas pipeline. We also own a 49.9 percent 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.

Contract Compression. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems.

Contract Treating. 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, to natural gas producers and midstream pipeline companies.

Corporate and Others. Our Corporate and Others segment comprises a small regulated pipeline and 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. For example, we seek to replace our longer term keep-whole arrangements as they expire or whenever the opportunity presents itself.

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

Transportation segment. We own a 49.99 percent general partner interest in HPC which, through RIG, delivers natural gas from northwest Louisiana to markets as well as downstream pipelines in northeast Louisiana through a 450-mile intrastate pipeline system. Results of HPC s operations are determined primarily by the volumes of natural gas transported on its intrastate pipeline system and the level of fees charged to the customers or the margins received from purchases and sales of natural gas. HPC generates revenues and segment margins principally under fee-based transportation contracts. The margin HPC earns is primarily related to fixed capacity reservation charges that are independent of throughput volumes or commodity prices. If a sustained decline in commodity prices should result in a decline in volumes, HPC s revenues from these arrangements would be reduced.

We own a 49.9 percent interest in MEP, a joint venture entity owning a natural gas pipeline with approximately 500 miles, and we account for our investment under the equity method of accounting. KMP owns a 50 percent interest in MEP and its affiliate acts as the operator of MEP. The MEP pipeline system originates near Bennington, Oklahoma and extends eastward through Texas, Louisiana and Mississippi, and terminates at an interconnection with the Transcontinental Gas Pipe Line near Butler, Alabama. The MEP pipeline system 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 on its intrastate pipeline system and the level of fees charged to the customers. MEP generates revenues and segment margins principally under fee-based transportation contracts. The margin MEP earns is directly related to the volume of natural gas that flows through its system and is not directly dependent on commodity prices. If a sustained decline in commodity prices should result in a decline in volumes, MEP s revenues would not be impacted until expiration of the current contracts.

Contract Compression segment. We own and operate a fleet of compressors used to provide turn-key natural gas compression services. We own and operate more than 844,000 horsepower of compression for customers in Texas, Louisiana, Arkansas and Pennsylvania. In addition, we operate approximately 115,000 horsepower of compression for our gathering and processing segment.

Contract Treating segment. 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, to natural gas producers and midstream pipeline companies.

HOW WE EVALUATE OUR OPERATIONS. Our 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, operating and maintenance expenses, EBITDA, and adjusted EBITDA on a segment and 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 Corporate and Others segment margin as our revenues generated from operations minus the cost of natural gas and NGLs purchased and other cost of sales, including third-party transportation and processing fees.

Prior to March 17, 2009, we calculated our Transportation segment margin as revenues generated by fee income as well as, in those instances in which we purchased and sold gas for our account, gas sales revenues minus the cost of natural gas that we purchased and transported. Since March 17, 2009, we have not recorded segment margin for the Transportation segment because we record our ownership percentage of the net income in HPC as income from unconsolidated subsidiaries. In addition, we record our ownership percentage of the net income in MEP as income from unconsolidated subsidiaries.

We calculate our Contract Compression segment margin as our revenues generated from our contract compression operations minus the direct costs, primarily compressor unit repairs, associated with those revenues.

We calculate our Contract Treating segment margin as revenues generated from our contract treating operations minus direct costs associated with those revenues.

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

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. We define adjusted total segment margin as total 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 our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.

Revenue Generating Gallons per Minute (GPM). Revenue generating GPM is the primary driver for revenue growth of the treating business in our contract treating segment. GPM is used as a measure of the treating capacity of an amine plant. Revenue generating GPM is our total GPM under contract less GPM that is not generating revenues.

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 separately evaluate commodity volume and price changes in segment margin.

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; and
- the Partnership s interest in adjusted EBITDA from unconsolidated subsidiaries less income from unconsolidated subsidiaries.

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 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.

Natural Gas Supply and Demand. Drilling rigs count increased to 919 rigs in December 2010 from 759 in December 2009, a 21 percent increase. The large price differential between NGLs and natural gas, on an energy equivalent basis, is expected to result in a shift toward increased drilling for oil and NGL-rich natural gas. In 2010, total marketed natural gas production increased by 4.1 percent with the increase in production primarily attributable to the lower 48 states. NGLs consumption increased in 2010, the major sources of growth were diesel fuel and heating oil.

Energy Outlook. In its annual energy outlook, the EIA expects natural gas production in 2011 to decrease by 0.3 percent, primarily in response to the lower natural gas prices. Average Henry Hub spot price for 2011 is

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forecasted to decline by $0.37 per MMBtu in part due to at or near record natural gas inventory and milder forecasted weather. Residential and commercial consumption of natural gas is forecasted to decline in 2011 and will be offset in part by an increase in industrial consumption. Overall natural gas consumption in 2011 is forecasted to decline by 0.9 percent. In 2012, natural gas consumption is projected to increase by 1.6 percent. The forecasted increases in natural gas consumption in 2012 coupled with the projected production decline in 2011 are expected to result in an increase natural gas prices in the latter part of 2011. NGLs consumption is projected to increase by 0.8 and 0.9 percent in 2011 and 2012, respectively.

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 did not have 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

Formation of HPC. On March 17, 2009, we completed a joint venture arrangement (HPC) among Regency HIG, EFS Haynesville and the Alinda Investors. We contributed RIGS valued at $401,356,000 in exchange for a 38 percent general partner interest in HPC. On September 2, 2009, we purchased an additional five percent general partner interest from EFS Haynesville for $63,000,000. On April 30, 2010, we purchased an additional 6.99 percent general partner interest from EFS Haynesville for $92,087,000, increasing our ownership percentage to 49.99 percent.

ETE Acquisition of GE EFS s Interest. On May 26, 2010, an affiliate of GE sold all of the outstanding membership interests of the General Partner to ETE. As a result of this transaction, the outstanding voting interests of the General Partner and control of the Partnership were transferred from this affiliate to ETE. In connection with this change in control, our assets and liabilities were adjusted to fair value on the closing date (May 26, 2010) by application of push-down accounting.

MEP Purchase. On May 26, 2010, we acquired a 49.9 percent interest in MEP and an option to acquire an additional 0.1 percent interest in MEP that is exercisable on May 27, 2011, from ETE. In return, we issued 26,266,791 of our common units, valued at $584,436,000 to ETE in a private placement, relying on Section 4(2) of the Securities Act and received a working capital adjustment of $4,632,000. As this transaction was between two entities under common control, it was accounted for in a manner silimar to a pooling of interest.

Disposition of East Texas Assets. On July 15, 2010, we sold our gathering and processing assets located in east Texas to an affiliate of Tristream Energy LLC for $70,180,000 in cash.

Acquisition of Zephyr. On September 1, 2010, we acquired Zephyr for $193,296,000 in cash.

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RESULTS OF OPERATIONS

Combined Year Ended December 31, 2010 vs. Year Ended December 31, 2009

	Combined Year Ended December 31, 2010					
	Successor	Predecessor		Predecessor		
	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to May 25, 2010	Total	Year Ended December 31, 2009	Change	Percent
	(in thousands except percentages)					
Total revenues	$ 716,613	$ 505,050	$ 1,221,663	$ 1,043,277	$ 178,386	17%
Cost of sales	504,327	357,778	862,105	674,944	187,161	28
Total segment margin[1]	212,286	147,272	359,558	368,333	(8,775)	2
Operation and maintenance	77,808	47,842	125,650	117,080	8,570	7
General and administrative	43,739	37,212	80,951	57,863	23,088	40
Loss (gain) on asset sales, net	213	303	516	(133,282)	133,798	100
Depreciation and amortization	75,967	41,784	117,751	100,098	17,653	18
Operating income	14,559	20,131	34,690	226,574	(191,884)	85
Income from unconsolidated subsidiaries	53,493	15,872	69,365	7,886	61,479	780
Interest expense, net	(48,251)	(34,541)	(82,792)	(77,665)	(5,127)	7
Loss on debt refinancing, net	(15,748)	(1,780)	(17,528)		(17,528)	100
Other income and deductions, net	(8,229)	(3,897)	(12,126)	(15,132)	3,006	20
(Loss) income from continuing operations before income taxes	(4,176)	(4,215)	(8,391)	141,663	(150,054)	106
Income tax expense (benefit)	552	404	956	(1,095)	2,051	187
Net (loss) income from continuing operations	$ (4,728)	$ (4,619)	$ (9,347)	$ 142,758	$ (152,105)	107
Discontinued operations	(1,244)	(327)	(1,571)	(2,269)	698	31
Net (loss) income	$ (5,972)	$ (4,946)	$ (10,918)	$ 140,489	$ (151,407)	108
Net income attributable to the noncontrolling interest	(156)	(406)	(562)	(91)	(471)	518
Net (loss) income attributable to Regency Energy Partners LP	$ (6,128)	$ (5,352)	$ (11,480)	$ 140,398	$ (151,878)	108%
Gathering and processing segment margin[2]	$ 110,011	$ 85,997	$ 196,008	$ 213,920	$ (17,912)	8%
Non-cash loss (gain) from commodity derivatives	23,033	7,150	30,183	(7,151)	37,334	522
Adjusted gathering and processing segment margin	$ 133,044	$ 93,147	$ 226,191	$ 206,769	$ 19,422	9%
Transportation segment margin				11,714	(11,714)	100
Contract compression segment margin[3]	91,853	62,356	154,209	141,028	13,181	9
Contract treating segment margin	11,454		11,454		11,454	100
Corporate and others segment margin[2]	13,047	8,045	21,092	6,275	14,817	236
Intersegment eliminations	(14,079)	(9,126)	(23,205)	(4,604)	(18,601)	404

Adjusted total segment margin	$ 235,319	$ 154,422	$ 389,741	$ 361,182	$ 28,559	8%

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(1) For reconciliation of segment margin to the most directly comparable financial measure calculated and presented in accordance with GAAP, please read Item 6. Selected Financial Data.
(2) Segment margins differ from previously disclosed amounts due to the presentation as discontinued operations for the disposition of our east Texas assets, as well as a functional reorganization of our operating segments.
(3) Contract Compression segment margin includes intersegment revenues of $23,205,000 and $4,604,000, for the years ended December 31, 2010 and 2009, respectively. These intersegment revenues were eliminated upon consolidation.

Net (Loss) Income Attributable to Regency Energy Partners LP. Net (loss) income attributable to Regency Energy Partners LP decreased to a loss of $11,480,000 in the year ended December 31, 2010 from a gain of $140,398,000 in the year ended December 31, 2009. The major components of this change were as follows:

$133,798,000 decrease in gain on asset sales, net primarily due to the absence of gain associated with the contribution of RIG to HPC;

$23,088,000 increase in general and administrative expenses primarily due to a $7,885,000 increase in unit-based compensation primarily related to the vesting of outstanding LTIP grants upon the acquisition of our General Partner by ETE, a $5,833,000 increase in service fees paid to Services Co. and a $3,504,000 increase in incentive related labor costs;

$17,653,000 increase in depreciation and amortization expense primarily related to the fair value adjustment of our long-lived assets upon the acquisition of our General Partner;

$17,528,000 loss on debt refinancing, net primarily related to the redemption premium paid to redeem our senior notes due 2013; and was offset by

$61,479,000 increase in income from unconsolidated subsidiaries primarily from the completion of HPC s expansion in early 2010, our increased general partner interest in HPC from 43 percent as of December 31, 2009 to 49.99 percent as of December 31, 2010 and the acquisition of a 49.9 percent interest in MEP in May 2010.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $389,741,000 in the year ended December 31, 2010 from $361,182,000 in the year ended December 31, 2009. The major components of this increase were as follows:

Adjusted Gathering and Processing segment margin increased to $226,191,000 for the year ended December 31, 2010 from $206,769,000 for the year ended December 31, 2009 primarily due to the increased volumes in south Texas associated with Eagle Ford Shale development as well as higher realized commodity prices. Total Gathering and Processing segment throughput increased to 996,800 MMBtu/d during the year ended December 31, 2010 from 975,963 MMBtu/d during the year ended December 31, 2009. Total NGL gross production increased to 26,155 Bbls/d during the year ended December 31, 2010 from 21,104 Bbls/d during the year ended December 31, 2009;

After our contribution of RIG to HPC on March 17, 2009, we do not record segment margin for the Transportation segment because we record our ownership percentage of the net income in HPC as income from unconsolidated subsidiaries. As a result, we reported no Transportation segment margin for the year ended December 31, 2010;

Contract Compression segment margin increased to $154,209,000 in the year ended December 31, 2010 from $141,028,000 in 2009. The increase was primarily attributable to the increased revenue generating horsepower provided to third parties and additional contract compression services provided to the Gathering and Processing segment.

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In addition to the revenue generating horsepower and compression units owned and operated by our Contract Compression segment disclosed below, our Contract Compression segment operates approximately 115,000 horsepower of compression for our Gathering and Processing segment as of December 31, 2010.

	Year Ended December 31,					
	2010			2009		
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	90,178	11%	453	65,397	9%	361
500-999	70,427	8%	111	74,826	10%	121
1,000+	684,195	81%	451	613,105	81%	405
	844,800	100%	1,015	753,328	100%	887

We acquired the Contract Treating segment on September 1, 2010; therefore there was no segment margin for the year ended December 31, 2009. Revenue generating GPM as of December 31, 2010 was 3,431;

Corporate and Others segment margin increased to $21,092,000 in the year ended December 31, 2010 from $6,275,000 in the year ended December 31, 2009, which was primarily attributable to an increase in the reimbursement from HPC for general and administrative expenses; and

Intersegment eliminations increased to $23,205,000 in the year ended December 31, 2010 from $4,604,000 in the year ended December 31, 2009. The increase was due to increased intersegment transactions between the Gathering and Processing and the Contract Compression segments.

Operation and Maintenance. Operation and maintenance expense increased to $125,650,000 in the year ended December 31, 2010 from $117,080,000 in the year ended December 31, 2009. The increase is primarily due to the following:

$3,872,000 increase in labor costs primarily from increased bonus accrual in 2010; and

$3,277,000 increased consumable products primarily utilized in our Contract Compression segment.

General and Administrative. General and administrative expense increased to $80,951,000 in the year ended December 31, 2010 from $57,863,000 in the year ended December 31, 2009. This increase is primarily the result of the following:

$7,885,000 increase in unit-based compensation primarily related to the vesting of outstanding LTIP grants upon the acquisition of our General Partner by ETE;

$5,833,000 increase in related party general and administrative expenses for the services fees paid to Services Co.;

$3,504,000 increase in labor costs primarily from increased incentive compensation accrual in 2010;

$1,948,000 increase in transaction costs primarily related to the ETE Acquisition and our acquisitions of MEP and Zephyr;

$1,258,000 increase in severance expenses primarily related to the integration of functions across a variety of operational and general and administrative departments with Services Co.; and

$798,000 increase in ad valorem taxes in the Contract Compression segment.

Loss (Gain) on Asset Sales, net. Loss (gain) on asset sales, net decreased to a loss of $516,000 in 2010 due to the absence in 2010 of $133,451,000 in gain attributable to the contribution of RIG to HPC.

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Depreciation and Amortization. Depreciation and amortization expense increased to $117,751,000 in the year ended December 31, 2010 from $100,098,000 in the year ended December 31, 2009. This increase was the result of $10,735,000 of additional depreciation and amortization expense incurred related to the fair value adjustment of our long-lived assets upon the acquisition of our General Partner. In addition, $6,918,000 of additional depreciation and amortization expense was the result of the completion of various organic growth projects since December 31, 2009. Had the change in control occurred on January 1, 2009, our depreciation and amortization expense for the years ended December 31, 2010 and 2009 would have been $125,419,000 and $118,501,000, respectively.

Interest Expense, Net. Interest expense, net increased to $82,792,000 in the year ended December 31, 2010 from $77,665,000 in the year ended December 31, 2009. The increase was primarily attributable to a full year of interest expense in 2010 associated with our $250,000,000 of 9 $^{3}/8$ percent senior notes due 2016 issued May 2009 as compared to only seven months in 2009. Also contributing to the increase was the issuance of $600,000,000 of 6 $^{7}/8$ percent senior notes due 2018 in October 2010.

Loss on debt refinancing, net. Loss on debt refinancing, net increased $17,528,000 in 2010 compared to 2009 primarily due to the redemption premium paid to redeem our senior notes due 2013.

Other Income and Deductions, net. Other income and deductions, net decreased $3,006,000 in 2010 compared to 2009 primarily due to the non-cash value change in the embedded derivatives related to the Series A Preferred Units issued in September 2009.

Year Ended December 31, 2009 vs. Year Ended December 31, 2008

	Year Ended December 31,			
	2009	2008	Change	Percent
	(in thousands except percentages)			
Total revenues	$ 1,043,277	$ 1,785,263	$ (741,986)	42%
Cost of sales	674,944	1,365,124	(690,180)	51
Total segment margin[1]	368,333	420,139	(51,806)	12
Operation and maintenance	117,080	119,715	(2,635)	2
General and administrative	57,863	51,323	6,540	13
(Gain) loss on asset sales, net	(133,282)	457	(133,739)	N/M
Management services termination fee		3,888	(3,888)	N/M
Transaction expenses		1,620	(1,620)	N/M
Depreciation and amortization	100,098	93,393	6,705	7

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	Year Ended December 31, 2009	2008	Change	Percent
	(in thousands except percentages)			
Operating income	$ 226,574	$ 149,743	$ 76,831	51%
Income from unconsolidated subsidiaries	7,886		7,886	N/M
Interest expense, net	(77,665)	(62,940)	(14,725)	23
Other income and deductions, net	(15,132)	328	(15,460)	N/M
Income from continuing operations before income taxes	141,663	87,131	54,532	63
Income tax benefit	(1,095)	(266)	(829)	312
Net income from continuing operations	$ 142,758	$ 87,397	$ 55,361	63
Discontinued operations	(2,269)	13,931	(16,200)	116
Net income	$ 140,489	$ 101,328	$ 39,161	39
Net income attributable to the noncontrolling interest	(91)	(312)	221	71
Net income attributable to Regency Energy Partners LP	$ 140,398	$ 101,016	$ 39,382	39%
Gathering and processing segment margin(2)	$ 213,920	$ 231,506	$ (17,586)	8%
Non-cash gain from commodity derivatives	(7,151)	(17,996)	10,845	60
Adjusted gathering and processing segment margin	206,769	213,510	(6,741)	3
Transportation segment margin	11,714	66,888	(55,174)	82
Contract compression segment margin(3)	141,028	125,503	15,525	12
Corporate and others segment margin(2)	6,275	815	5,460	670
Inter-segment eliminations	(4,604)	(4,573)	(31)	1
Adjusted total segment margin	$ 361,182	$ 402,143	$ (40,961)	10%

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

(2) Segment margins differ from previously disclosed amounts due to the presentation as discontinued operations for the disposition of our east Texas assets, as well as a functional reorganization of our operating segments.

(3) Contract Compression segment margin includes intersegment revenues of $4,604,000 and $4,573,000, for the years ended December 31, 2009 and 2008, respectively. These intersegment revenues were eliminated upon consolidation.

N/M Not meaningful.

Net Income Attributable to Regency Energy Partners LP. Net income attributable to Regency Energy Partners LP increased to $140,398,000 in the year ended December 31, 2009 from $101,016,000 in the year ended December 31, 2008. The increase is primarily due to the recording of a $133,451,000 gain associated with the contribution of RIG to HPC, $7,886,000 in income from HPC and the absence in 2009 of $3,888,000 of management service termination fees related to the acquisition of our FrontStreet assets in 2008. These increases were partially offset by:

- a decrease in total segment margin of $51,806,000 due primarily to the contribution of RIG to HPC on March 17, 2009 as well as lower commodity prices;

- a decrease in other income and deductions, net of $15,460,000 which primarily relates to the non-cash value change associated with the embedded derivative related to the Series A Preferred Units issued in September 2009;

an increase in interest expense of $14,725,000 related primarily to the issuance of $250,000,000 of senior notes due 2016 in May 2009 at a higher interest rate as compared to our credit facility interest rate;

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an increase in depreciation and amortization expense of $6,705,000 related primarily to organic growth projects completed in 2009; and

an increase in general and administrative expenses of $6,540,000 primarily due to an increase in employee-related expenses.

Adjusted Total Segment Margin. Adjusted total segment margin decreased to $361,182,000 in the year ended December 31, 2009 from $402,143,000 in the year ended December 31, 2008. The major components of this change were as follows:

Adjusted Gathering and Processing segment margin decreased to $206,769,000 for the year ended December 31, 2009 from $213,510,000 for the year ended December 31, 2008. The decrease was primarily related to lower commodity prices compared to 2008 price levels, as well as a decrease in margin in our producer services function. Total Gathering and Processing segment throughput decreased to 975,963 MMBtu/d during the year ended December 31, 2009 from 997,551 MMBtu/d during the year ended December 31, 2008. Total NGL gross production increased to 21,104 Bbls/d during the year ended December 31, 2009 from 19,569 Bbls/d during the year ended December 31, 2008;

Transportation segment margin decreased to $11,714,000 for the year ended December 31, 2009 from $66,888,000 for the year ended December 31, 2008, which was primarily attributable to the contribution of RIG to HPC on March 17, 2009;

Contract Compression segment margin increased to $141,028,000 in the year ended December 31, 2009 from $125,503,000 in 2008. The increase is attributable to higher revenue generating horsepower in the first half of 2009 compared to the same period in 2008. The Contract Compression segment margin is also enhanced by the exclusion of 15 days in 2008 due to the timing of our CDM acquisition.

In addition to the revenue generating horsepower and compression units owned and operated by our Contract Compression segment disclosed below, our Contract Compression segment operates approximately 149,000 horsepower of compression for our Gathering and Processing segment as of December 31, 2009.

	Year Ended December 31,					
	2009			2008		
Horsepower Range	**Revenue Generating Horsepower**	**Percentage of Revenue Generating Horsepower**	**Number of Units**	**Revenue Generating Horsepower**	**Percentage of Revenue Generating Horsepower**	**Number of Units**
0-499	65,397	9%	361	59,288	7%	351
500-999	74,826	10%	121	83,299	11%	134
1,000+	613,105	81%	405	636,080	82%	425
	753,328	100%	887	778,667	100%	910

Despite the decrease in the amount of drilling activity during 2009, we only experienced a three percent decrease in revenue generating horsepower due to successful renewals of our customer contracts; and

Corporate and Others segment margin increased to $6,275,000 in the year ended December 31, 2009 from $815,000 in 2008. The increase is primarily due to the reimbursement from HPC for general and administrative expenses.

Operation and Maintenance. Operation and maintenance expense remained relatively consistent with the year ended December 31, 2008, declining $2,635,000 in 2009, a two percent decrease.

General and Administrative. General and administrative expense increased to $57,863,000 in the year ended December 31, 2009 from $51,323,000 in 2008. This increase is primarily the result of the following factors:

$3,925,000 increase in employee-related expenses due to increased employer benefits payments and incentive compensation accruals; and

$1,301,000 increase in professional and consulting service fees.

(Gain) Loss on Asset Sales, net. Gain on asset sales, net in 2009 primarily consisted of $133,451,000 in gain attributable to the contribution of RIG to HPC.

Depreciation and Amortization. Depreciation and amortization expense increased to $100,098,000 in the year ended December 31, 2009 from $93,393,000 in the year ended December 31, 2008. The increase was primarily due to:

$18,355,000 increase related to various organic growth projects completed since December 31, 2008; offset by

$11,650,000 decrease in depreciation expense related to the contribution of RIG to HPC.

Interest Expense, Net. Interest expense, net increased to $77,665,000 in the year ended December 31, 2009 from $62,940,000 in 2008. This increase was primarily attributable to the issuance of $250,000,000 of 9 3/8 percent senior notes in May 2009.

Other Income and Deductions, net. Other income and deductions, net decreased $15,460,000 in 2009 compared to 2008 primarily due to the non-cash value change in the embedded derivatives related to the Series A Preferred Units issued in September 2009.

Results of Operation for HPC

Although we own a 49.99 percent general partner interest in HPC, the following management discussion and analysis is for 100 percent of HPC s consolidated results of operations. For comparative purposes only, we have combined the results of operations of RIG from January 1, 2009 to March 17, 2009, with the results of operations of HPC from inception (March 18, 2009) to December 31, 2009.

Year Ended December 31, 2010 vs. Year Ended December 31, 2009

The table below contains key HPC performance indicators related to our discussion of the results of its operations.

	Year Ended December 31, 2010	2009	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 176,597	$ 56,730	$ 119,867	211%
Cost of sales	2,250	4,679	(2,429)	52
Segment margin	174,347	52,051	122,296	235
Operation and maintenance	17,518	9,697	7,821	81
General and administrative	17,759	5,702	12,057	211
Loss on asset sales, net	105		105	100
Depreciation and amortization	31,797	10,962	20,835	190
Operating income	107,168	25,690	81,478	317
Interest expense	(526)	(158)	(368)	233
Other income and deductions, net	95	1,335	(1,240)	93
Net income	$ 106,737	$ 26,867	$ 79,870	297%
Throughput (MMbtu/d)	1,277,881	738,654	539,227	73%

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The following provides a reconciliation of segment margin to net income.

	Year Ended December 31, 2010	2009
	(in thousands)	
Net income	$ 106,737	$ 26,867
Add (deduct):		
Operation and maintenance	17,518	9,697
General and administrative	17,759	5,702
Loss on asset sales, net	105	
Depreciation and amortization	31,797	10,962
Interest expense	526	158
Other income and deductions, net	(95)	(1,335)
Segment margin	$ 174,347	$ 52,051

Net income increased to $106,737,000 in the year ended December 31, 2010 from $26,867,000 in the year ended December 31, 2009. The increase in net income was primarily attributable to the following:

- an increase in segment margin of $122,296,000 primarily from HPC s expansion projects being placed in service on January 27, 2010, which increased revenues primarily from firm transportation agreements; and was partially offset by

- an increase in depreciation and amortization expense of $20,835,000 primarily as a result of the additional depreciation from HPC s expansion projects;

- an increase in general and administrative expense of $12,057,000 primarily due to fees paid to the Partnership by HPC;

- an increase in operation and maintenance expense of $7,821,000 mainly resulting from an increase of $4,666,000 of ad valorem taxes and an increase of $2,676,000 in related party costs of compression from HPC s expansion projects being placed in service on January 27, 2010; and

- a decrease in other income and deductions of $1,240,000 primarily from interest earned on the cash contributions in 2009.

Capital Contribution. In February 2010, HPC received cash capital contribution of $47,000,000, of which the Partnership contributed its pro-rata share of $20,210,000 to HPC.

Cash Distributions. During the years ended December 31, 2010 and 2009, HPC made cash distributions of $147,612,000 and $23,110,000, respectively, of which the Partnership received its respective pro-rata share of $65,114,000 and $8,925,000, respectively.

In addition, on August 9, 2010, HPC made a return of investment to its partners of $40,000,000 from the cost savings on its expansion project, of which the Partnership received its pro-rata share of $19,995,000.

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Year Ended December 31, 2009 vs. Year Ended December 31, 2008

The table below contains key HPC performance indicators related to our discussion of the results of its operations.

	Year Ended December 31, 2009	2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 56,730	$ 68,921	$ (12,191)	18%
Cost of sales	4,679	2,033	2,646	130
Segment margin	52,051	66,888	(14,837)	22
Operation and maintenance	9,697	3,540	6,157	174
General and administrative	5,702	9	5,693	N/M
Loss on asset sales, net		44	(44)	N/M
Depreciation and amortization	10,962	14,099	(3,137)	22
Operating income	25,690	49,196	(23,506)	48
Interest expense	(158)		(158)	N/M
Other income and deductions, net	1,335	11	1,324	N/M
Net income	$ 26,867	$ 49,207	$ (22,340)	45%
Throughput (MMbtu/d)	738,654	770,939	(32,285)	4%

N/M Not meaningful

The following provides a reconciliation of segment margin to net income.

	Year Ended December 31, 2009	2008
	(in thousands)	
Net income	$ 26,867	$ 49,207
Add (deduct):		
Operation and maintenance	9,697	3,540
General and administrative	5,702	9
Loss on asset sales, net		44
Depreciation and amortization	10,962	14,099
Interest expense	158	
Other income and deductions, net	(1,335)	(11)
Segment margin	$ 52,051	$ 66,888

Net income decreased to $26,867,000 in the year ended December 31, 2009 from $49,207,000 in the year ended December 31, 2008. The decrease in net income was primarily attributable to the following:

- a decrease in segment margin of $14,837,000 primarily due to the decrease in natural gas prices and volumes;

an increase in operation and maintenance expense of $6,157,000 mainly resulting from an increase of $2,041,000 of contractor maintenance expenses for compression operations and the absence in 2009 of $3,134,000 in insurance reimbursement related to a compressor fire;

an increase in general and administrative expense of $5,693,000 primarily due to management fees paid to us by HPC;

an increase in other income and deductions of $1,324,000 primarily from interest earned on the cash contributions; and were partially offset by

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a decrease in depreciation and amortization expense of $3,137,000 primarily as a result of the valuation of RIG s assets upon contribution to HPC as well as the revision of useful lives of the tangible assets.

HPC s adjusted EBITDA for the years ended December 31, 2010, 2009 and 2008 are presented below.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Net income	$ 106,737	$ 26,867	$ 49,207
Add (deduct):			
Depreciation and amortization	31,797	10,962	14,099
Interest expense	526	158	
EBITDA	$ 139,060	$ 37,987	$ 63,306
Add (deduct):			
Gain on insurance settlement	(242)		(3,134)
Loss on assets sales	105		44
Other expense, net	14	50	33
Adjusted EBITDA	$ 138,937	$ 38,037*	$ 60,249

* Adjusted EBITDA for the year ended December 31, 2009 comprises adjusted EBITDA of $9,581,000 related to RIG for the period from January 1, 2009 to March 17, 2009 and adjusted EBITDA of $28,456,000 related to HPC for the period from March 18, 2009 to December 31, 2009.

Results of Operation for MEP

We purchased a 49.9 percent interest in MEP from ETE on May 26, 2010. Although we own a 49.9 percent interest in MEP, the following management discussion and analysis is for 100 percent of MEP s results of operations.

Year Ended December 31, 2010 vs. December 31, 2009

The table below contains key MEP performance indicators related to our discussion of the results of its operations.

	Year Ended December 31,			
	2010	2009	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 221,817	$ 98,593	$ 123,224	125%
Cost of sales	9,472	9,139	333	4
Segment margin	212,345	89,454	122,891	137
Operation and maintenance	35,123	7,208	27,915	387
General and administrative	3,132	1,072	2,060	192
Depreciation and amortization	66,929	33,398	33,531	100
Operating income	107,161	47,776	59,385	124
Interest expense	(47,288)	(18,720)	(28,568)	153
Other income and deductions, net	300	194	106	55
Net income	$ 60,173	$ 29,250	$ 30,923	106%

Throughput (MMbtu/d)	1,408,778	678,104	730,674	108%

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The following provides a reconciliation of segment margin and adjusted segment margin to net income.

	Year Ended December 31, 2010	2009
	(in thousands)	
Net income	$ 60,173	$ 29,250
Add (deduct):		
Operation and maintenance	35,123	7,208
General and administrative	3,132	1,072
Depreciation and amortization	66,929	33,398
Interest expense	47,288	18,720
Other income and deductions, net	(300)	(194)
Segment margin and adjusted segment margin	$ 212,345	$ 89,454

Net income increased to $60,173,000 in the year ended December 31, 2010 from $29,250,000 in the year ended December 31, 2009. The increase in net income was primarily attributable to an increase in segment margin of $122,891,000 primarily due to a full year of operations of Zone 1 and Zone 2, which were completed in May and August 2009, respectively. In addition there was an expansion project completed in June 2010, which further increased total pipeline capacity from 1.5 Bcf/d to 1.8 Bcf/d. This increase was partially offset by:

$33,531,000 increase in depreciation and amortization expense primarily related to the expansion project;

$27,915,000 increase in operation and maintenance primarily due to higher ad valorem taxes of $22,865,000; and

$28,568,000 increase in interest expense primarily related to the issuance of $800,000,000 senior notes in September 2009.

MEP s adjusted EBITDA for the years ended December 31, 2010 and 2009 are presented below.

	Year Ended December 31, 2010	2009
	(in thousands)	
Net income	$ 60,173	$ 29,250
Add:		
Depreciation and amortization	66,929	33,398
Other expense	47,288	18,720
EBITDA and adjusted EBITDA	$ 174,390	$ 81,368

Capital Contribution. During the period from May 26, 2010 to December 31, 2010, MEP received cash capital contributions of $172,000,000, of which the Partnership contributed its pro-rata share of $85,828,000.

Cash Distributions. During the period from May 26, 2010 to December 31, 2010, the Partnership received $43,306,000 of distributions from MEP.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our revolving credit facility;

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- distributions received from unconsolidated subsidiaries;
- asset sales;
- debt offerings; and
- issuance of additional partnership units.

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 capital is also influenced by current derivative assets and liabilities due to fair value changes in our derivative positions being reflected on our balance sheet. 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 Compression and Contract Treating segments record 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 decreased to a deficit of $35,145,000 at December 31, 2010 from a surplus of $17,468,000 at December 31, 2009, a decrease of $52,613,000. This decrease was primarily due to the following factors:

- a decrease in derivative assets of $22,337,000, primarily due to settlement of the 2010 trades, higher hedged prices compared to previous year price levels and new trades entered into since December 2009;
- an increase in other current liabilities of $11,051,000, primarily due to interest accrual on our senior notes due 2018 issued in October 2010; and
- an increase in trade accounts payable of $5,296,000, primarily due to the timing of payments.

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 to our future liquidity.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $169,207,000 in the year ended December 31, 2010 from $143,960,000 in the year ended December 31, 2009. The increase was primarily due to an increase in distributions from unconsolidated subsidiaries.

Net cash flows provided by operating activities decreased to $143,960,000 in the year ended December 31, 2009 from $181,298,000 in the year ended December 31, 2008. The decrease is primarily due to the contribution of our RIG assets to HPC and lower commodity prices in 2009 compared to 2008.

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 increased to $444,879,000 in the year ended December 31, 2010 from $156,165,000 in the year ended December 31, 2009. The increase was primarily due to the acquisition of our Contract Treating assets and an increase in capital contributions to unconsolidated subsidiaries.

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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, 2010, we incurred $193,401,000 of growth capital expenditures, excluding Contract Treating segment. Growth capital expenditures for the year ended December 31, 2010 primarily related to $121,390,000 for organic growth projects in our Gathering and Processing segment, $67,471,000 for the fabrication of new compressor packages for our Contract Compression segment and $4,540,000 related to our Corporate and Others segment.

In addition, in the year ended December 31, 2010, we made capital contributions of $20,210,000 and $85,828,000 to HPC and MEP, respectively.

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, 2010, we incurred $14,761,000 of maintenance capital expenditures.

Net cash flows used in investing activities decreased to $156,165,000 in the year ended December 31, 2009 from $948,629,000 in the year ended December 31, 2008. The decrease is attributable to the absence of major acquisitions during the year and a decrease in organic growth projects, exclusive of HPC s expansion project, in 2009.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $275,245,000 in the year ended December 31, 2010 from $21,433,000 in the year ended December 31, 2009. The increase was primarily due to the following:

- a net decrease in our revolving credit facility repayments of $214,445,000;
- an increase in net proceeds from equity issuance of $179,175,000; and were partially offset by
- the absence in 2010 of $76,624,000 in proceeds related to the issuance of the Series A Preferred Units;
- a net increase in partners distributions of $58,123,000; and
- an increase in debt issuance cost of $15,893,000 primarily related to the amendment of our revolving credit facility and the issuance of the senior notes due 2018.

Net cash flows provided by financing activities decreased to $21,433,000 in the year ended December 31, 2009 from $734,959,000 in the year ended December 31, 2008. The decrease was primarily due to the following:

- a decrease in net borrowing under our credit facility of $993,816,000;
- an increase in partner distribution of $25,994,000;
- A payment of $10,197,000 in 2009 as a deemed distribution resulting from an acquisition of assets from an affiliate of our General Partner as between entities under common control in excess of historical cost; and were offset by
- a $226,956,000 increase in net proceeds from debt issuance; and

a $92,225,000 increase in net proceeds from issuance of common units and Series A Preferred Units including our General Partner s contributions to maintain its two percent interest.

Capital Resources

Description of Our Indebtedness. As of December 31, 2010, our aggregate outstanding indebtedness totaled $1,141,061,000 and consisted of $285,000,000 in borrowings under our revolving credit facility and $856,061,000 of outstanding senior notes as compared to our aggregate outstanding indebtedness as of December 31, 2009, which totaled $1,014,299,000 and consisted of $419,642,000 in borrowings under our revolving credit facility and $594,657,000 of outstanding senior notes.

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Revolving Credit Facility. In March 2010, we entered into the Fifth Amended and Restated Credit Agreement that extended the maturity date of this facility to June 15, 2014 from August 15, 2011. In May 2010, the Fifth Amended and Restated Credit Agreement amended certain definitions to include MEP, to allow for the pledge of the equity interest in MEP as indirect collateral to permit certain investments in MEP by the Partnership and its affiliates and to require that the Partnership and its subsidiaries maintain a senior consolidated secured leverage ratio not to exceed three to one.

We have a $900,000,000 revolving credit facility and the availability for letters of credit is $100,000,000. We also have the option to request an additional $250,000,000 in revolving commitments with ten business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the revolving credit facility have been met. We are allowed to make additional investments in HPC up to $250,000,000 as well as other joint venture investments (other than HPC) of up to $75,000,000.

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 of revolving loans 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 percent and an adjusted one-month LIBOR rate plus 1.00 percent. The applicable margin shall range from 1.50 percent to 2.25 percent for base rate loans, 2.50 percent to 3.25 percent for Eurodollar loans, and a commitment fee will range from 0.375 to 0.50 percent.

We must pay (i) a commitment fee equal to 0.375 percent per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit equal to 2.5 percent 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 percent per annum of the average daily amount of the letter of credit exposure.

The revolving credit facility contains financial covenant requiring RGS and its subsidiaries to maintain debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.25. At December 31, 2010 and 2009, 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 2013. During the fourth quarter of 2010, in connection with the issuance of $600,000,000 of senior notes due 2018 as further described below, the Partnership redeemed all of its $357,500,000 senior notes due 2013.

Senior Notes due 2018. In October, 2010, the Partnership and Finance Corp. issued $600,000,000 of senior notes that mature on December 1, 2018. The senior notes bear interest at 6 $^{7}/8$ percent paid semi-annually in arrears on June 1 and December 1, commencing June 1, 2011. The Partnership capitalized $12,196,000 in debt issuance costs that will be amortized to interest expense, 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 revolving credit facility.

At any time before December 1, 2013, up to 35 percent of the senior notes can be redeemed at a price of 106.875 percent plus accrued interest. Beginning December 1, 2014, the Partnership may redeem all or part of these notes for the principal amount plus a declining premium prior to December 31, 2016, and thereafter at par, plus accrued and unpaid interest. At any time prior to December 1, 2014, the Partnership may also redeem all or part of the notes at a price equal to 100 percent of the principal amount redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) one percent 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.

Upon a change of control (as defined) followed by a rating decline within 90 days, each holder of senior notes due 2018 will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent 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.

The senior 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 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, 2010, the Partnership was in compliance with these covenants.

Senior Notes due 2016. In May 2009, the Partnership and Finance Corp. issued $250,000,000 of senior notes that mature on June 1, 2016. The senior notes bear interest at 9 $^{3}/8$ percent with interest payable semi-annually in arrears on June 1 and December 1. The Partnership received net proceeds of $236,240,000 upon issuance. The net proceeds were used to partially repay revolving loans under the Partnership s revolving credit facility.

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At any time before June 1, 2012, up to 35 percent of the senior notes can be redeemed at a price of 109.375 percent plus accrued interest. Beginning June 1, 2013, the Partnership may redeem all or part of these notes for the principal amount plus a declining premium prior to June 1, 2015, and thereafter at par, plus accrued and unpaid interest. At any time prior to June 1, 2013, the Partnership may also redeem all or part of the notes at a price equal to 100 percent of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) one percent 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.

Upon a change of control (as defined), each noteholder will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent 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.

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, 2009, the Partnership was in compliance with these covenants.

Both the senior notes due 2018 and the senior notes due 2016 are jointly and severally guaranteed by all of the Partnership s current consolidated subsidiaries, other than Finance Corp. and a minor subsidiary, 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.

Letters of Credit. At December 31, 2010, we had outstanding letters of credit totaling $16,015,000 under our revolving credit facility. The total fees for letters of credit accrue at a current annual rate of 2.625 percent, which is applied to the daily amount of letters of credit exposure.

HPC Working Capital Facility. As of February 7, 2011, RIG has a $100,000,000 working capital facility that expires on July 27, 2014. We believe RIG s working capital facility will reduce the likelihood of us having to fund our proportionate share of HPC s working capital needs in the future.

Equity Offerings. In August 2010, we sold 17,537,500 common units in an underwritten public offering, and received $408,100,000 in proceeds, inclusive of the General Partner s proportionate capital. On May 26, 2010, we issued 26,266,791 common units, valued at $584,436,000, to ETE, to purchase a 49.9 percent interest in

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MEP. These units were issued in a private placement exempt from the registration requirements of the Securities Act, under Section 4(2) thereof. Subsequently, ETE also contributed $12,288,000 as the General Partner s proportionate capital.

Other - MEP Guarantee. Upon our acquisition of the 49.9 percent interest in MEP from ETE, we agreed to indemnify ETP for any costs related to ETP s guarantee of payments under MEP s senior revolving credit facility (the MEP Facility). ETP will continue to guarantee 50 percent of the obligations of the MEP Facility, with the remaining 50 percent of MEP Facility obligations guaranteed by KMP. The $175,400,000 MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both ETP s credit rating and that of KMP, with a maximum fee of 0.15 percent. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of December 31, 2010, MEP had no outstanding borrowings and $33,300,000 of letters of credit issued under the MEP Facility. Our contingent obligations with respect to MEP s letters of credit under the MEP Facility were $16,600,000 as of December 31, 2010.

Contractual Obligations. The following table summarizes our total contractual cash obligations as of December 31, 2010.

	Payments Due By Period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
			(in thousands)		
Long-term debt (including interest)(1)	$ 1,648,660	$ 78,899	$ 153,338	$ 419,235	$ 997,188
Operating leases(2)	22,849	4,172	6,296	4,666	7,715
Purchase obligations(3)	39,161	39,161			
Distributions and redemption of Series A Preferred Units(4)	229,792	7,781	15,563	15,563	190,885
Related party cash obligations	44,167	10,000	20,000	14,167	
Total(5)	$ 1,984,629	$ 140,013	$ 195,197	$ 453,631	$ 1,195,788

(1) Assumes a constant LIBOR interest rate of 0.78 plus applicable margin (2.50 percent as of December 31, 2010) for our revolving credit facility. The principal of our outstanding senior notes ($850,000,000) bears a weighted average fixed rate of 7.61 percent.

(2) Included within the future operating lease cash obligation is a Master Lease Agreement between CDM and Caterpillar Financial Services Corporation, with an annual rent expense of $1,224,000. CDM exercised an early buyout option on January 14, 2011, to purchase the leased compression equipment for $9,000,000 and terminated the agreement.

(3) 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.

(4) Assumes that the Series A Preferred Units are redeemed for cash on September 2, 2029, and the annual distribution is $7,781,000.

(5) Excludes deferred tax liabilities of $6,185,000 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 generates the deferred tax liability.

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OTHER MATTERS

Legal. We are involved in various claims, 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.

IRS Audits. The IRS commenced audits of the Partnership s tax returns on January 27, 2010. The Partnership understands this to be a routine audit of various items of partnership income, gain, deductions, losses and credits. The audit is ongoing and the IRS has proposed various adjustments to the Partnership s tax returns, which the Partnership expects to appeal. It is not known whether such adjustments would be material, or how such adjustments would affect unitholders. Copies of the Notice of Beginning of Administrative Proceeding to the Partnership dated January 27, 2010 stating that the IRS is commencing audits of the Partnership s 2007 and 2008 partnership tax returns are attached as exhibits hereto.

In addition, as of December 31, 2009, the IRS is conducting an audit to the tax returns of Pueblo Holdings Inc., one of our wholly-owned subsidiaries, for the tax years ended December 31, 2007 and December 31, 2008.

The statute of limitations for each of these audits has been extended to December 31, 2012. We, through our tax matters 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 Valuation. 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 the components of a segment and how segment 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. 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 compression or treating 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.

As-if Pooling of Interest Method of Accounting. We account for acquisitions where common control exists by following the as-if pooling method of accounting. Under this method of accounting, we reflect the historical balance sheet data for both the acquirer and acquiree instead of reflecting the fair market value of the acquiree s assets and liabilities. In acquisitions of entities under common control where a minority interest is also acquired, we use the purchase method of accounting for the minority interest where the minority interest is not under common control.

Equity Method Investments. The equity method of accounting is used to account for our interest in investments of greater than 20 percent 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 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 judgment 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.

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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 was 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.

Derivatives. Our financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate and commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate and commodity swaps 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.

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 Risk Management Committee of our General Partner is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The Risk Management 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

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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 execute natural gas, NGLs and WTI trades on a periodic basis to hedge our anticipated equity exposure. Our swap contracts settle against condensate, ethane, propane, butane, natural gas and natural gasoline market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge positions as conditions warrant. We have hedged expected exposure to declines in prices for NGLs, condensate and natural gas volumes produced for our account in the approximate percentages set for below:

	As of December 31, 2010		As of January 31, 2011	
	2011	2012	2011	2012
NGLs	88%	31%	88%	47%
Condensate	84%	37%	84%	55%
Natural gas	76%	25%	76%	25%

The following table sets forth certain information regarding our hedges for natural gas, NGLs, and WTI, outstanding at December 31, 2010. 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. The fair value of our outstanding trades is determined using a discounted cash flow model based on third-party prices and readily available market information.

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive Weighted Average Price		Fair Value Asset/(Liability)	Effect of Hypothetical Change in Index*
							(in thousands)	
January 2011-June 2012	Ethane	783	(MBbls)	Index	$ 0.49	($/gallon)	$ (1,060)	$ 1,692
January 2011-September 2012	Propane	444	(MBbls)	Index	1.00	($/gallon)	(4,203)	2,277
January 2011-September 2012	Normal Butane	276	(MBbls)	Index	1.35	($/gallon)	(2,914)	1,863
January 2011-September 2012	Natural Gasoline	153	(MBbls)	Index	1.74	($/gallon)	(2,314)	1,355
January 2011-September 2012	West Texas Intermediate Crude	374	(MBbls)	Index	84.08	($/Bbl)	(3,581)	3,501
January 2011-June 2012	Natural gas	3,830,000	(MMBtu)	Index	5.29	($/MMBtu)	2,053	1,684
January 2011-April 2012	Interest Rate	$ 250,000,000		1.325%	Three-month LIBOR		(2,584)	3,125
					Total Fair Value		$ (14,603)	

* Price risk sensitivities were calculated assuming a theoretical 10 percent change, increase or decrease, 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 credit-worthy 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.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of December 31, 2010, the Partnership had $285,000,000 of outstanding borrowings, of which $35,000,000 were exposed to variable interest rate risk.

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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.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, as appropriate to allow timely decisions regarding required disclosure.

Our management does not expect that our disclosure controls and procedures will prevent all errors. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all our disclosure control issues have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. The design of any system of controls also is based in part on certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurance of achieving our desired control objectives.

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, 2010.

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.

Those rules define internal control over financial reporting as a process designed by, or under the supervision of our General Partner s principal executive and principal financial officers and effected by its Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and include those policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

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Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our General Partner s management and directors; and

Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statement.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

Management of our General Partner assessed the effectiveness of our internal control over financial reporting as of December 31, 2010. 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.

On September 1, 2010, we acquired Zephyr. Management has acknowledged that it is responsible for establishing and maintaining a system of internal controls over financial reporting for Zephyr. We are in the process of integrating Zephyr, and we therefore excluded Zephyr from our December 31, 2010 assessment of the effectiveness of internal control over financial reporting. Zephyr had total assets of $220,584,000 and total third party revenue of $13,662,000 from September 1, 2010 to December 31, 2010 included in our consolidated financial statements as of and for the year ended December 31, 2010. The impact of the acquisition of Zephyr has not materially affected and is not expected to materially affect our internal control over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. We believe, however, that we will be able to maintain sufficient controls over the substantive results of our financial reporting throughout this integration process.

Based on its assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2010.

(b) *Audit Report of the Registered Public Accounting Firm.* KPMG 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.

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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.

Investor Rights Agreement. In connection with the sale of our General Partner in May 2010, we and the owner of our General Partner entered into an Investor Rights Agreement with an affiliate of GE EFS, the former owner of our General Partner, that provides that GE or its affiliates may elect to designate two investor directors or two non-voting investor observers for as long as an affiliate of GE owns at least 15 percent of our common units that it held as of May 26, 2010. In addition, if the number of common units held by an affiliate of GE falls below 15 percent, but continues to exceed 10 percent, of the number held as of May 26, 2010, then an affiliate of GE has the right to designate one investor director or investor observer. During 2010, Mr. James F. Burgoyne and Mr. Paul J. Halas served as designated observers for GE s affiliate.

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 NASDAQ. 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.

Our Board of Directors currently consists of five members, three of whom qualify as independent under NASDAQ 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 of Senior Financial Officers, and the charters of our audit, compensation and nominating committees are available on our website at www.regencyenergy.com. You may also contact our investor relations department at (214) 840-5467 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. Please 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 Committee. The Board of Directors has established an Audit 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 NASDAQ s standards for audit committee members, to serve on its Audit Committee. In addition, the Board of Directors determined that at least one member, Rodney L. Gray, the chairman of the Audit 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.

The Audit 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 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 Committee deems advisable. The Audit 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 Committees), and makes recommendations to the Board of Directors for inclusion in our audited financial statements on this Form 10-K.

The Audit Committee is authorized to recommend to the Board of Directors any changes or modifications to its charter that the Audit 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 Risk Management 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 Committee reviews risks related to financial reporting. The Audit 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 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 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 Committee and, as required, are reported to the full 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 independent directors are required by those rules to meet in executive session at least twice each year. In practice, they meet in executive session at most regularly-scheduled meetings of the Board. Interested parties may make their concerns known to the independent directors directly and anonymously by writing to the Chairman of the Audit 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 February 17, 2011. Executive officers and directors are elected for indefinite terms.

Name	Age	Position with Regency GP LLC
Michael J. Bradley	56	Director, President and Chief Executive Officer
Thomas E. Long	53	Executive Vice President and Chief Financial Officer
Paul M. Jolas	46	Executive Vice President, Chief Legal Officer and Secretary
A. Troy Sturrock	40	Vice President, Controller and Principal Accounting Officer
John D. Harkey, Jr.	50	Chairman of the Board of Directors
John W. McReynolds	60	Director
Rodney L. Gray	59	Director
James W. Bryant	77	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 and Chief Executive Officer 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.

Paul M. Jolas was elected executive vice president, chief legal officer and secretary of Regency GP LLC on September 8, 2009. Mr. Jolas has more than 20 years of legal experience, including extensive experience with corporate, securities, governance, finance and transitional matters. Prior to joining Regency, he served in various legal roles at Dallas-based Trinity Industries, Inc. (NYSE: TRN) from June 2006 through September 2009, most recently as vice president, deputy general counsel and corporate secretary. Previous to his work at Trinity, he served as senior regional counsel for the Texas division of KB Home from 2004 to 2006; from 1996 to 2003, he served as general counsel, executive vice president and corporate secretary for Radiologix, Inc.; and from 1989 to 1996, as a member of the corporate securities group for Haynes and Boone, LLP. Mr. Jolas received a Bachelor of Arts degree in Economics from Northwestern University and a Juris Doctor degree from Duke University School of Law.

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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 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. From December 2005 to May 2010, Mr. Harkey served as a Director of Energy Transfer Partners, L.P., and has served as a Director of Energy Transfer Equity, L.P. since May 2006. In addition, Mr. Harkey has served as Chief Executive Officer and Chairman of Consolidated Restaurant Companies, Inc. since 1998. He 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 also serves on the President s Development Council of Howard Payne University, Baylor Health Care Foundation and on the Executive Board of Circle Ten Council of the Boy Scouts of America. Among the reasons for Mr. Harkey s appointment as a director are 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 the President and Chief Financial Officer of Energy Transfer Equity, L.P. and has served as the President of ETE since March 2005 and as a Director and Chief Financial Officer of ETE since August 2005. In addition, from August 2004 to May 2010, he served as a Director of Energy Transfer Partners, L.P. Prior to becoming President of ETE, Mr. McReynolds was a partner at an international law firm 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. 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. On June 1, 2009, Mr. Gray was appointed 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 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 experience as a Chief Financial Officer of a public company in the oil exploration and production industry.

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 ten percent 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 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, with the following exceptions, during the fiscal year ended December 31, 2010 our General Partner s executive officers, directors and greater than ten percent common unitholders filed all reports they were required to file under Section 16(a). A Form 3 for LE GP, LLC reflecting its status as a 10 percent owner as of May 26, 2010 was filed on December 13, 2010. Forms 4 for Aircraft Services Corp., an affiliate of GE, reflecting the sale of common units on December 2, 2010 and October 25, 2010 were filed on December 9, 2010 and October 28, 2010, respectively. A Form 3 for James W. Bryant was filed July 22, 2010 reflecting his status as a director as of July 1, 2010. A Form 4 for L. Patrick Giroir, Jr. reflecting the sale of common units on May 28, 2010 was filed on June 8, 2010. A Form 4 for David G. Marrs reflecting the sale of common units on May 24, 2010 was filed on May 27, 2010. A Form 3 for L. Patrick Giroir, Jr. was filed March 16, 2010 reflecting his status as an executive officer as of August 10, 2009. A Form 4 for Dennie W. Dixon reflecting the sale of common units on February 2, 2010 was filed on February 24, 2010.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

Overview of Our Executive Compensation Program

On May 26, 2010 (the Change of Control Date), a subsidiary of Energy Transfer Equity, L.P., a Delaware partnership (ETE) purchased our General Partner (the Change of Control). As a result of this transaction, control of the Partnership was transferred from General Electric Energy Financial Services (GE EFS) to ETE. The Change of Control led to changes in the composition of our Board of Directors and of our management team. Concurrently with the consummation of the transaction, five members of the Board of Directors of our General Partner (James F. Burgoyne, Daniel R. Castagnola, Paul J. Halas, Mark T. Mellana and Brian P. Ward), all of whom were designees of GE EFS, resigned as directors of our General Partner, and ETE appointed two other individuals (John W. McReynolds and John D. Harkey, Jr.) to our General Partner s Board. Certain other senior leaders, including our Chief Executive Officer, our Chief Financial Officer and certain other executive officers, resigned during the remaining portion of 2010.

This Compensation Discussion and Analysis describes the compensation policies and decisions of our Compensation Committee (the Committee) with respect to our executive officers, including the following individuals who are referred to as the Named Executive Officers, or NEOs :

- Michael J. Bradley, President and Chief Executive Officer;
- Byron R. Kelley, former Chairman of the Board, President and Chief Executive Officer;

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- Thomas E. Long, Executive Vice President and Chief Financial Officer;

- A. Troy Sturrock, Vice President, Controller, Principal Accounting Officer and former interim Principal Financial Officer;

- Stephen L. Arata, former Executive Vice President and Chief Financial Officer;

- Paul M. Jolas, Executive Vice President, Chief Legal Officer and Secretary;

- Dennie W. Dixon, former Senior Vice President, Operations for Gathering and Processing and Transportation Segments (who resigned effective January 10, 2011);

- David G. Marrs, former President of Contract Compression Segment; and

- L. Patrick Giroir, former Executive Vice President and Chief Commercial Officer of Gathering and Processing and Transportation Segments.

As further described below, our philosophy regarding the overall objectives of our compensation programs remains unchanged following the Change of Control. Our compensation program is designed to recruit and retain individuals with the highest capacity to develop and grow our business, and to align their compensation with the short and long-term goals of our business. To accomplish these objectives, our compensation program consists of the following components: (a) base salary, designed to compensate employees for work performed during the fiscal year; (b) short-term incentive compensation, designed to reward employees for the Partnership s yearly performance and for individual performance goals achieved during the fiscal year; and (c) long-term incentive compensation in the form of equity awards, meant to align our NEOs interests with the Partnership s long-term performance.

While our compensation philosophy remains unchanged, we did modify our equity awards program in connection with the Change of Control. Specifically, we changed the timing of our annual grant of equity awards as well as the type of equity awards we grant to our executive officers in order to better align our equity award program with that of Energy Transfer Partners, L.P. (ETP), a master limited partnership whose ultimate owner is ETE. We do not anticipate changes to other components of our compensation program at this time. However, if the Committee makes any material changes to the compensation program, those changes will be disclosed on a Form 8-K.

Role of the Committee and Management

The General Partner is responsible for the management of the Partnership. The Committee is appointed by the Board of Directors of the General Partner to discharge the Board s responsibilities relating to compensation of the Partnership s executive officers. The Committee is directly responsible for the General Partner s incentive compensation programs, which include programs that are designed specifically for our senior officers, including our Named Executive Officers.

The Committee is charged, among other things, with the responsibility of reviewing the executive officer compensation policies and practices to ensure (a) adherence to our compensation philosophy and (b) that the total compensation paid to our executive officers is fair, reasonable and competitive. The Committee meets at least twice yearly, with one of its meetings focused on a review of compensation programs for executive officers. Following this annual review, the Committee makes recommendations to the Board for its approval.

During the first quarter of each fiscal year, our Board, based on information and recommendations provided by senior management, approves corporate objectives for the Partnership, including a budget, for the year. These corporate objectives may differ from, and may exceed, the projections of anticipated performance of the Partnership that we provide to the investing public from time to time. The Board also at this time determines the aggregate amount of the payout under the annual incentive bonus pool for executive officers and employees for the preceding year.

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Also during the first quarter of each year, the Committee meets to (a) assess the performance of the CEO and other senior officers with respect to the Partnership s results for the preceding year, (b) review and assess the personal performance objectives of the senior officers for the preceding year, if any, and (c) determine the portion of the approved bonus pool to be paid to the executive officers. Our CEO participates in the process of allocating the Partnership bonus pool among different business groups and makes recommendations to the Committee regarding the amount of bonuses and other compensation that should be paid to other members of senior management, including the other executive officers.

In addition, the Committee, at these meetings and after taking into account both the advice of outside consultants and recommendations of senior management, considers base salary levels, target bonus levels and awards to be made under the LTIP for ensuing fiscal years for our executive officers. Effective as of the Change of Control Date, the Committee determined that it would consider whether to grant equity awards in December, rather than in the first quarter of the year, to better align our equity grant program with that of ETP.

Compensation Philosophy and Objectives

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

In establishing our compensation programs, we consider the following compensation objectives:

- to create unitholder value through generation of sustainable earnings and cash available for distribution;
- to reward participants for value creation commensurate with industry standards and the pay practices of our competitors;
- to provide a significant percentage of total compensation that is at-risk or variable;
- to encourage significant equity ownership to align the interests of executive officers and key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship, cooperation among business units and employee pay.

We also strive to achieve a fair balance between the compensation rewards that we perceive as necessary to remain competitive in the marketplace and fundamental fairness to our unitholders, taking into account the return on their investment.

In measuring the contributions of our executive officers and our performance, the Committee considers the following financial and operating measures:

- Adjusted EBITDA, which is defined in Item 6. Selected Financial Data as further adjusted and described under Compensation Components and Analysis Annual Incentive Bonuses ;
- the amount of distributions paid with respect to all of our outstanding common units;

our ability to control and manage general and administrative expenses and operations and maintenance expenses;

the total reportable incident rate, which is a measure of the number of injury accidents involving employees over the calendar year; and

the number of preventable vehicle accidents.

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The Committee elected to utilize these measures for gauging the performance of the Partnership in 2010 as a means of incentivizing executives to meet our financial goals, to deliver growth in unitholder value and to ensure the safety of our employees, the environment, and the communities in which we operate.

Market Analysis

In 2010, to ensure that our compensation practices were competitive, the Committee retained BDO Seidman, LLP (BDO), to provide a total compensation analysis for our executive officers and certain key employees. The Committee selected a peer group that includes the 20 publicly-traded limited partnerships listed below, which are in the midstream market segment of the oil and gas industry. In selecting this peer group, we considered those of our competitors that are of a size similar to our own, measured by market capitalization. Our market capitalization falls in the median range of the peer group, which consists of the following 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.

In addition to our peer group, the Committee relies on the expertise of BDO in order to obtain a more complete picture of the overall compensation environment. BDO provides us with market data and analysis regarding board and executive compensation, based on proprietary surveys of companies in our industry. Where possible, BDO provides us with information regarding the pay practices of similarly-sized master limited partnerships, but supplements the data with information from the broader market where necessary. The data is proprietary and is provided to us in summary fashion.

When considering the data, the Committee generally seeks to position the total compensation of our Named Executive Officers at the median range by reference to persons with similar duties at our peer group companies. The Committee also seeks to reward our executive officers when we achieve our stretch performance goals by providing compensation that is in the upper quartile of our peer group. However, actual compensation decisions for individual officers are the result of the Committee s subjective analysis of a number of factors, including the individual officer s performance, experience, skills or tenure with us, changes to the individual s position and trends in compensation practices within our peer group or industry. Each executive s current and prior compensation is considered in setting future compensation. The amount of each executive s current compensation is considered as a base against which the Committee makes determinations as to whether adjustments are necessary to retain the executive in light of competition and in order to provide continuing performance incentives. Thus, the Committee s determinations regarding compensation are the result of the exercise of judgment based on all reasonably available information and, to that extent, are discretionary. The Committee may use its discretion to adjust any of the components of compensation to achieve our goal of recruiting, promoting and retaining individuals with the skills necessary to execute our business strategy and develop and grow our business.

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Elements of Compensation Programs

Overall, the executive compensation programs are designed to be consistent with the philosophy and objectives set forth above. The principal elements of our executive compensation programs are summarized in the table below, followed by a more detailed discussion of each compensation element.

Element	Characteristics	Purpose
Base salary	Fixed annual cash compensation; executive officers are eligible for periodic increases in base salary based on individual performance; targeted to approximate the 50th percentile in pay level of our peer group.	Keep our annual compensation competitive with the defined market for skills and experience necessary to execute our business.
Annual incentive bonus	Performance-based annual cash incentive earned based on achievement of corporate objectives and individual objectives, if any, against target performance levels; awards are targeted to range between the 50th and the 75th percentile of our peer group.	Align performance to the corporate objectives that drive our business and reward executive officers for achievement of both corporate and individual performance objectives. Amounts earned for achievement of target performance levels are designed to provide competitive total cash compensation; potential for lesser or greater amounts are intended to motivate executives to achieve or exceed our financial and operational goals.
Equity based awards (phantom units)	Awards of phantom units are based on personal and corporate performance. Effective as of the Change of Control Date, forfeiture restrictions on phantom units will lapse according to the passage of time. In general, units with time-based restrictions vest as to 1/5 of the award on each of the first five anniversaries of the award date. Distribution equivalent rights (DERS) accompany equity grants. The recipient has a right to distributions based on the entire unit award, rather than just the portion that has vested. Equity awards granted in prior years (and those granted in May 2010) consisted of phantom units that were subject to different vesting provisions, both as to the phantom unit and as to any distributions related to an accompanying DER, as discussed more fully below.	Align the interest of executive officers with unitholders; motivate and reward executive officers to increase unitholder value over the long term. The vesting schedule facilitates retention of executive officers.

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Element	Characteristics	Purpose
Retirement savings plan	Tax-deferred 401(k) plan in which all employees can choose to defer compensation for retirement up to IRS imposed limits ($16,500 for 2010). In 2010, we matched a participant s contributions to the 401(k) plan, up to six percent of eligible compensation, but not greater than $16,500. Effective January 1, 2011, we match participant s contributions up to five percent of eligible compensation, and matching contributions vest immediately.	Provide the opportunity and incentivize employees to save for their future retirement.
Health and welfare benefits	Health and welfare benefits (medical, dental, vision, disability insurance and life insurance) are available for all regular full-time employees.	Provide benefits to meet the health and wellness needs of employees and their families.

Compensation Components and Analysis

Base Salary

Design. Base salaries are generally targeted at the market median of our peer group of companies, although each executive officer may have a base salary above or below the median of the market. Actual individual salary amounts are not objectively determined, but instead reflect the Committee s subjective analysis of a number of factors, including the individual officer s experience, skills or tenure with the Partnership, changes to the individual s position within the Partnership, or trends in compensation practices within our peer group or industry. In addition, the Committee also carefully considered the input and recommendations of the CEO when evaluating factors relative to the other executive officers, or, in the case of the CEO, the Committee considered the input and recommendations of the chairman of the Committee.

2010 Fiscal Year Results. The following table shows the base salaries of our Named Executive Officers and the percentage increases that the 2010 base salary represents over the prior year s base salary, where applicable.

Named Executive Officer	2010 Salary	Percentage Increase Over Prior Year
Michael J. Bradley	$ 575,000	N/A
Byron R. Kelley	$ 504,000	3%
Thomas E. Long	$ 300,000	N/A
A. Troy Sturrock	$ 182,500	7%
Stephen L. Arata	$ 283,300	N/A
Paul M. Jolas	$ 360,000	20%
Dennie W. Dixon	$ 215,300	N/A
David G. Marrs	$ 300,000	N/A
L. Patrick Giroir	$ 236,500	N/A

The Board approved a three percent salary increase for Mr. Kelley on October 19, 2010, which was effective as of July 5, 2010 and consistent with the increases generally made to base salaries of full-time employees who are not officers. Mr. Sturrock s base salary increase, which was effective on July 5, was a result of his promotion to a new position. Following the acquisition of our General Partner by Energy Transfer Equity, L.P., Mr. Jolas received a 20 percent increase in his base salary in recognition of his performance and his contributions in connection with the transaction. The Board did not consider increasing salaries for Messrs. Arata, Dixon, Marrs and Giroir because of their tendered or expected resignations.

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While our stated goal is to approximate the base salaries of the 50th percentile of our peer group of companies, we believe that it is important, in some cases, to deviate from this goal in order to attract the best talent for critical positions within the Partnership. The base salaries of Messrs. Long, Sturrock, Arata, Dixon and Marrs approximate the 50th percentile of salaries of individuals in comparable positions at our peer group of companies. Mr. Giroir had been recently promoted to his current position, and as a result, his base salary fell below the 50th percentile of similarly situated officers, who in many cases have longer tenure in their roles. Base salary compensation for Messrs. Bradley and Kelley exceed the salaries of chief executive officers at the 75th percentile of our peer group of companies as a result of salary negotiations in a competitive environment. Mr. Jolas salary exceeds the salaries of officers holding a similar position at the 75th percentile of our peer group of companies, which reflects Mr. Jolas performance, contribution to our performance, and the decision to seek to retain Mr. Jolas following the acquisition of our General Partner.

Changes for Fiscal Year 2011. As of the date of this Annual Report on Form 10-K, the Committee has not approved any changes to the base salaries for fiscal year 2011.

Guaranteed Minimum Bonus

In connection with the negotiation of employment terms with Messrs. Bradley and Long, we agreed to pay them guaranteed minimum bonuses for fiscal year 2011. We believe it was important to provide this one-time element of compensation in light of the highly competitive employment environment and in order to recruit these individuals to our company. The amounts of the guaranteed bonuses are substantially the same as the amounts that each of Messrs. Bradley and Long would otherwise be entitled to receive under our annual incentive bonus program if target performance is achieved. However, these guaranteed amounts will be paid regardless of whether the company or the executive meet their respective 2011 performance goals. Mr. Bradley s minimum bonus will be $500,000. Mr. Long s minimum bonus will be $250,000. Bonuses for fiscal year 2011 are anticipated to be paid in February or March 2012.

Annual Incentive Bonuses

Design. Annual incentive bonuses are targeted to range between the 50th and 75th percentile of our peer group of companies. As reflected in the table below titled NEO Target Bonus Opportunity, if target goals are achieved, the Named Executive Officers are eligible to receive an annual bonus opportunity ranging from 40 percent to 100 percent of base salary. To arrive at a payout amount for a particular NEO, the Committee first determines the amount of funding of the Partnership s bonus pool, which is funded based on the achievement of certain Partnership performance goals, discussed below. In May 2010, the Committee budgeted a total target bonus pool of $12.3 million, which was based on the sum of each employee s target bonus opportunity, expressed as a percentage of each employee s wages. For 2010, whether the Partnership funded the total amount of the target bonus pool depended on Partnership performance related to the following corporate performance measures:

- Adjusted EBITDA, which is defined in Item 6. Selected Financial Data as further adjusted and described under Compensation Components and Analysis Annual Incentive Bonuses ;
- the amount of distributions paid with respect to all of our outstanding common units;
- our ability to control and manage general and administrative expenses and operations and maintenance expenses;
- the total reportable incident rate, which is a measure of the number of injury accidents involving employees over the calendar year; and
- the number of preventable vehicle accidents.

Each of these performance metrics is weighted and is subject to a threshold, target and stretch performance goal. The table below shows the weighting assigned to each performance metric and describes the amount of the bonus pool that will accrue if the performance metric indicated is achieved. The annual incentive

bonus pool is prorated if actual performance falls between the defined threshold and stretch corporate performance targets. For 2010, the corporate performance targets were:

				Percentage Accrual of Pool		
Performance Metric	**Threshold**	**Target**	**Stretch**	**Threshold**	**Target**	**Stretch**
Adjusted EBITDA (millions)	$ 244.1	$ 265	$ 277.6	25%	60%	100%
Per Common Unit Cash Distributions	$ 1.68	$ 1.78	$ 1.80	12.5%	25%	37.5%
Cash Management (G&A and O&M) (millions)	$ 190.1	$ 181.1	$ 166.6	7.5%	15%	26.5%
Total Reportable Incident Rate	2.96	2.08	1.64	2.5%	5%	7.5%
Preventable Vehicle Accidents	13	11	8	2.5%	5%	7.5%
Total Bonus Pool Accrual				50%	110%	179%

The Committee has the discretion to apply a zero to two times multiplier to the amount of the final bonus pool, such that the amount of the bonus pool may range from no bonus up to approximately 358 percent of the bonus pool accrual. This discretionary multiplier allows the Committee to either reward extraordinary corporate performance or reduce the bonus pool accrual in response to current business conditions or other factors.

Once the Committee decides the funding of the Partnership-wide bonus pool based on the Partnership s achievement of corporate performance goals, the bonus pool is allocated among different business groups according to each group s achievement of group-specific performance targets. In 2010, our NEOs were members of the Corporate group. The Committee set business group-specific performance targets, the achievement of which determines the actual amount of the bonus pool available for distribution to the individuals in that group.

For 2010, the Corporate group s bonus pool accrued on the same basis as the company-wide bonus pool, but the pool s size was tied to the wages of each employee in the Corporate group. The Committee budgeted a target bonus pool of $2,203,000 for the Corporate group, which represents the sum of the target bonus opportunity for each employee in the individual group, determined as a percentage of each employee s wages. The CEO has discretion to allocate between 10 and 20 percent of the Partnership s bonus pool among the different business groups, as a means of recognizing significant achievement during the year.

Once the Committee and the CEO have allocated the bonus pool among the individual business groups, the CEO makes bonus recommendations to the Committee for each NEO, excluding himself, based on each NEO s personal performance during the year. The Committee s evaluation of individual performance takes into account a range of factors that may vary for individual officers, and may include effective leadership, teamwork, customer focus, safety, environmental stewardship, the development of individuals responsible to the applicable officer, and the officer s role within the Partnership. Any amounts awarded are subject to the Committee s discretion.

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The following table describes each Named Executive Officer s target bonus opportunity, calculated as a percentage of base salary, and the percentage of base salary that the actual award earned for fiscal year 2010 represented. Messrs. Bradley and Long, who joined our company in late 2010, were ineligible to participate in our 2010 annual incentive bonus program.

NEO Target Bonus Opportunity

Named Executive Officer	Target Performance	Annual Incentive Bonus Award as a % of Salary
Michael J. Bradley	N/A	N/A
Byron R. Kelley	100%	170%
Thomas E. Long	N/A	N/A
A. Troy Sturrock	40%	52%
Stephen L. Arata	75%	N/A
Paul M. Jolas	75%	87%
Dennie W. Dixon	75%	75%
David G. Marrs	90%	31%
L. Patrick Giroir	75%	N/A

Fiscal Year 2010 Results. In assessing the Partnership s performance with respect to its stated corporate performance goals, the Committee determined it was appropriate to consider the impact of the Change of Control as well the sale of our east Texas assets. Specifically, the Committee approved the modification of the definition of Adjusted EBITDA (solely for purposes of determining the Annual Incentive Bonus) to (i) present Adjusted EBITDA on a pre-bonus expense basis, (ii) exclude the impact of our acquisition of a 49.9 percent interest in MEP, (iii) exclude the impact of our east Texas operations and (iv) exclude the amount of the fees paid to ETE pursuant to the services agreement. The adjustments in (i), (iii) and (iv) were also applied to the calculation of our 2010 results for the Cash Management performance metric. Accordingly, the following table shows the Partnership s 2010 performance results as determined by the Committee for purposes of determining the Annual Incentive Bonus:

Performance Metric	Financial Results
Adjusted EBITDA, as further adjusted	$ 278,942,000
Per Common Unit Cash Distributions	$ 1.78
Adjusted Cash Management (G&A and O&M)	$ 147,228,000
Total Reportable Incident Rate	1.22
Preventable Vehicle Accidents	5

In light of the adjustments above, the Committee also determined it was appropriate to modify the threshold, target and stretch performance goals for Adjusted EBITDA, as further adjusted and Adjusted Cash Management, both as described in the immediately preceding paragraph. In addition, the Committee determined that it was appropriate to exclude non-cash LTIP expense from the budgeted goals because it is no longer reported within Adjusted EBITDA. The modified performance goals are reflected in the following table:

				Percentage Accrual of Pool		
Performance Metric	Threshold	Target	Stretch	Threshold	Target	Stretch
Adjusted EBITDA, as further adjusted (millions)	$ 256.4	$ 269.9	$ 291.4	25%	60%	100%
Adjusted Cash Management (G&A and O&M) (millions)	$ 159.9	$ 152.3	$ 140.1	7.5%	15%	26.5%

With respect to Per Common Unit Cash Distributions, we achieved the target performance goal. With respect to Total Reportable Incident Rate and Preventable Vehicle Accidents, we achieved the stretch performance goal. We exceeded our target goals in each of the performance metrics listed in the table immediately preceding this paragraph. Collectively, these achievements resulted in the bonus pool accruing at 136%.

While the Committee has the discretion to make subjective adjustments based on a range of individual performance factors that may vary for each NEO, the Committee did not exercise this discretion in 2010. Instead, as further described below, the Committee awarded annual incentive bonuses based upon the 2010 corporate performance measures in the following amounts:

Named Executive Officer	2010 Annual Incentive Bonus Award ($)
Michael J. Bradley	N/A
Byron R. Kelley	856,800
Thomas E. Long	N/A
A. Troy Sturrock	95,514
Stephen L. Arata	
Paul M. Jolas	313,449
Dennie W. Dixon	161,475
David G. Marrs	95,000
L. Patrick Giroir	

Messrs. Bradley and Long, who commenced employment with us in late 2010, were ineligible to participate in our 2010 incentive bonus program.

Under the terms of Mr. Kelley s employment agreement, if company target goals are achieved, he is eligible to receive an annual bonus award equal to 100 percent of his base salary. In November 2010, in connection with Mr. Kelley s resignation, the Committee evaluated the Partnership s annualized performance and determined that stretch targets had been achieved. Based on the Partnership s achievement of its stretch performance objectives and in consideration of Mr. Kelley s execution of a consulting agreement with the Partnership, the Committee determined it was appropriate to apply a 1.7x multiplier to Mr. Kelley s bonus target.

The amounts awarded to Messrs. Jolas and Sturrock were based on the Partnership s performance as compared against the 2010 performance goals described above.

The amount awarded to Mr. Marrs was based on the terms of his separation agreement.

Under the terms of his severance agreement, Mr. Dixon received his target bonus amount of $161,475. In light of their respective resignations, Messrs. Arata and Giroir were not entitled to receive bonus awards.

Changes for Fiscal Year 2011. As of the date of this Annual Report on Form 10-K, the Committee has not approved any changes to the annual incentive compensation program for fiscal year 2011.

Equity-Based Awards

Design. Our equity awards are granted under our LTIP, which provides a source of equity to attract new members to our management team to incentivize key employees. We believe the LTIP promotes a long-term focus on our results and aligns employee and unitholder interests.

Historically, equity awards granted under our LTIP have been targeted at market median levels, consistent with our practice of keeping total compensation to our employees at market median levels. Since 2009, it has

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been our practice to grant equity awards in the form of phantom units, which are subject to certain vesting restrictions. The vesting restrictions on our phantom units have lapsed based either on the passage of time, with vesting dependent on continued employment as of each applicable vesting date, or on the achievement of certain market-based performance metrics related to Total Unitholder Return (TUR). In 2009 and in May 2010, 40 percent of phantom units granted were subject to time-based vesting restrictions and 60 percent were subject to performance-based vesting restrictions. Time-based restrictions typically lapse as to one-third of any unit award on each of the first three anniversaries of the date of grant. TUR is determined through a formula that measures the price per unit plus the cash distributions per unit at the end of a specified period, divided by the price per unit at the beginning of that specified period. The units subject to vesting restrictions related to TUR vest at the end of a three-year period based on our performance compared against a group of our peer companies. In addition, phantom units have traditionally been granted with tandem DERs, which entitle the grantee to a cash distribution with respect to a unit while such phantom unit is outstanding.

Historically, the Committee has granted phantom awards to our NEOs in the first or second quarter of the year as consideration for prior year performance. In 2010, considering the pending Change of Control, the Committee elected to grant phantom unit awards to the NEOs on May 7, 2010 to incentivize their continued performance. Accordingly, the vesting provisions of these phantom unit awards did not accelerate when the change of control transaction occurred shortly after the May 7 grant. The number of units awarded to each NEO on May 7 was at the market median level of awards made by our peer group of companies to officers in similar roles. In an effort to further our retention efforts, the tandem DERs associated with the May 2010 grants accumulate and will only pay out as the underlying phantom unit vests.

Following the Change of Control, we significantly modified our equity award program. Our primary objective was to align the features of our equity award program with those of ETP s equity award program. ETP grants equity awards that are subject only to time-based vesting requirements, which it believes is more generally prevalent with the companies in the energy industry with which it competes for talented employees. ETP also grants annual equity awards in December as consideration for current year performance. Accordingly, in December 2010, we granted phantom unit awards that vest over a five-year period at 20 percent per year, subject to continued employment through each specified vesting date. In determining the size of the December 2010 equity awards, the Committee approved grants equal in value to a designated percentage of the officer s salary. The designated percentage was determined by the Committee s review of the prior three-year average size of equity awards as a percentage of base salary for officers holding similar positions at ETP. Finally, consistent with ETP s practice, the tandem DERs associated with the December 2010 grants will be paid out on a current basis at the same time that any distributions are made to our unitholders generally.

2010 Fiscal Year Results. For 2010, the Committee made the following phantom unit awards to NEOs, each of which includes a tandem DER grant:

Named Executive Officer	Total Number of Units Awarded
Michael J. Bradley	100,000
Byron R. Kelley	73,000
Thomas E. Long	38,500
A. Troy Sturrock	13,500
Stephen L. Arata	14,000
Paul M. Jolas	40,500
Dennie W. Dixon	7,000
David G. Marrs	14,500
L. Patrick Giroir	13,500

Messrs. Bradley and Long received an initial grant of 50,000 units and 15,000 units, respectively, in connection with our employment of them and our desire to encourage equity ownership by our executive officers.

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Each of Messrs. Bradley, Long, Sturrock and Jolas received December equity awards the size of which, as described above, was consistent on a percentage basis with equity awards granted by ETP to executive officers holding similar positions at ETP.

Mr. Kelley received 40,000 units in May 2010, which was at the market median of awards made to executive officers at our peer group of companies. He received an additional grant of 33,000 in consideration of his entering into a consulting arrangement with the Partnership. The grant of units to Messrs. Arata, Dixon, Marrs and Giroir in May 2010 were also at the market median of awards made to officers holding similar positions at our peer group of companies. Pursuant to the terms of his employment agreement, Mr. Marrs is entitled to a pro-rata portion of the 8,700 phantom units subject to performance-based vesting restrictions that were granted to him on May 7, 2010, based upon his continued employment with the Partnership for approximately 30 days after the date of grant. These 267 phantom units will vest on March 15, 2013 based upon the achievement of certain metrics related to TUR. The units granted to Messrs. Arata and Giroir were forfeited upon their resignations.

Changes for Fiscal Year 2011. As of the date of this Annual Report on Form 10-K, the Committee has not approved any changes to the LTIP program, other than the changes made in connection with the Change of Control, as discussed above.

Deferred Compensation

Among our peer group of companies, tax-deferred 401(k) plans are a common way that companies assist employees in preparing for retirement. We provide our eligible officers and employees with an opportunity to participate in our tax-deferred 401(k) savings plan. The plan allows executive officers to defer compensation for retirement up to the IRS imposed limits of $16,500 for 2010. In 2010, the Partnership matched dollar for dollar up to 6 percent of eligible compensation, and the matching contribution vested ratably over three years. Effective January 1, 2011, our 401(k) plan merged with and into that of ETP. As a result of the merger, Partnership contributions that had not yet fully vested became fully vested, effective immediately. For 2011, we will match contributions up to 5 percent of eligible compensation, with immediate vesting. Decisions regarding this element of compensation do not impact any other element of compensation.

In addition, beginning in 2011, employees earning more than $125,000 will have the option to participate in a Deferred Compensation Plan. The Deferred Compensation Plan is designed to provide employees with the ability to enhance savings and retirement accumulation on a tax-advantaged basis, beyond the limits of traditional qualified retirement plans. Eligible employees can defer up to 50 percent of each of base compensation, quarterly unit distributions, and annual incentive bonus on a pre-tax basis.

Perquisites

Perquisites are not a significant factor in our compensation structure. During salary negotiations, the Partnership agreed to reimburse Messrs. Bradley and Long for temporary living expenses associated with commuting to Dallas, and certain moving expenses in connection with relocation to Dallas. The Partnership had previously agreed to provide Messrs. Kelley and Giroir with a housing allowance of $4,500 per month and $3,333 per month, respectively. Mr. Kelley s housing allowance ended in December 2010. Mr. Giroir s housing allowance ended in May 2010.

Employment Agreements, Severance Benefits and Change of Control Provisions

We have previously entered into employment agreements and we maintain other compensatory agreements with some of our officers for a variety of reasons, including the fact that employment agreements can be an important recruiting tool in the market in which we compete for talent. Certain provisions in these agreements, such as confidentiality, non-solicitation, and non-compete clauses, protect the Partnership and its unitholders

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after the termination of the employment relationship. We believe that it is appropriate to compensate former employees for these post-termination agreements, and that compensation helps to enhance the enforceability of these arrangements. We have also entered into separation or severance agreements with certain executive officers upon their termination of service in order to clarify our obligations with respect to severance or benefit obligations to those executives as well as to document the executives release of claims against us relating to their employment. In connection with the Change of Control, we have made certain payments to executives pursuant to these agreements, as discussed above. In addition, we have entered into a consulting arrangement with Mr. Kelley pursuant to which Mr. Kelley will provide us with consulting services for a period of three years. These agreements are described in more detail elsewhere in this document. Please read Executive Compensation Potential Payments Upon a Termination or Change of Control.

Recoupment Policy

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

Class B Units

In connection with the acquisition of our General Partner by an affiliate of General Electric Company (the Former Owner) in June 2007, certain members of our management team purchased Class B membership interests in our General Partner. The Committee considers the Class B interests to be investments, rather than compensation, because management purchased the Class B interests with cash or through an exchange of membership interests in the pre-acquisition Partnership. Consequently, the values attributable to the Class B units and any distributions made with respect to those units are not included in the summary compensation table. When ETE purchased our General Partner on the Change of Control Date, the Former Owner received preferred units in ETE (ETE Preferred Units) in exchange for the purchase. The Former Owner expects to distribute the ETE Preferred Units to its Class B Unitholders as a distribution-in-kind in connection with the liquidation of the Former Owner.

Compensation Committee Report

We have reviewed and discussed with management certain compensation discussion and analysis provisions to be included in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2010 to be filed pursuant to Section 13(a) of the Securities and Exchange Act of 1934 (the Annual Report). Based on those reviews and discussions, we recommend to the Board of Directors of the General Partner that the Compensation Discussion and Analysis be included in the Annual Report.

Compensation Committee

John D. Harkey, Jr., Chairman

John W. McReynolds

Rodney L. Gray

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COMPENSATION TABLES AND NARRATIVES

Summary Compensation Table for 2010

Name and Principal Position	Year	Salary ($)	Stock Awards ($)(4)	Non Equity Incentive Plan Compensation ($)	All Other Compensation ($)(5)	Total ($)
Michael J. Bradley(1)	2010	44,231	2,447,500		10,701	2,502,432
President and Chief Executive Officer						
Byron R. Kelley(2)	2010	457,289	1,645,690	856,800	341,900	3,301,679
	2009	480,481	333,520	425,000	264,484	1,503,485
Former Chairman of the Board,						
President and Chief Executive Officer	2008	356,250	2,813,761	400,000	72,189	3,642,200
Thomas E. Long(1)	2010	15,000	965,750		11,630	992,380
Executive Vice President and Chief Financial Officer						
A. Troy Sturrock(1)	2010	176,038	315,511	95,514	25,734	612,797
Chief Accounting Officer and Interim Principal Financial Officer						
Stephen L. Arata(2)	2010	209,206	282,044		94,380	585,630
	2009	278,192	166,760	170,000	17,329	632,281
Former Executive Vice President and Chief Financial Officer	2008	268,750		208,200	10,029	486,979
Paul M. Jolas(1)	2010	310,060	918,232	313,449	48,506	1,590,247
Executive Vice President, Chief Legal Officer and Secretary						
Dennie W. Dixon(3)	2010	215,300	141,022	161,475	40,642	558,439
	2009	187,808	230,204	137,500	56,244	611,756
Former Senior Vice President, GP&T						
David G. Marrs(2)(3)	2010	140,769	292,117	95,000	361,311	889,197
	2009	260,671	183,436	216,000	15,942	676,049
Former President of Contract Compression Segment						
L. Patrick Giroir(2)(3)	2010	113,702	271,971		87,957	473,630
	2009	223,021	83,380	133,000	88,960	528,361
Former Executive Vice President and Chief Commercial Officer of Gathering and Processing and Transportation Segments						

(1) The year 2010 is the first year in which Messrs. Bradley, Long, Sturrock and Jolas are considered Named Executive Officers, and therefore the information provided in the Summary Compensation Table for these individuals is for the year 2010 only.

(2) The employment of Messrs. Kelley, Arata, Marrs and Giroir with the Partnership ended in 2010. The Summary Compensation Table presents compensation information for a partial year, including salary earned until the termination of employment and any additional

compensation received as a result. Mr. Kelley s compensation also reflects a 3 percent increase in base salary approved by the Board on October 19, 2010, but effective as of July 5, 2010, which increased Mr. Kelley s base compensation to $504,000.

(3) Compensation values reported in the Summary Compensation Table for Messrs. Marrs, Giroir and Dixon include only amounts related to 2010 and 2009 as each became a Named Executive Officer in 2009.

(4) The amount included in the Stock Awards column reflects the aggregate grant date fair value of all awards granted for the year ended December 31, 2010, 2009 and 2008, computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in Note 17 to the audited consolidated financial statements included in this Annual Report for the fiscal year ended December 31, 2010.

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The Stock Awards column includes values for phantom units that are subject to a market condition (the comparison of the TUR of the Partnership s common units against the TUR of the common units of the Partnership s peer group). The value for these phantom units was calculated by multiplying the grant date fair value price of $19.81 by the number of units granted (which is also the number of units the Named Executive Officer would receive if the Partnership achieves target performance). Because these phantom units are subject to a market condition, the grant date fair value price accounts for the possibility that the maximum level-of-performance condition is satisfied. The amounts set forth in the table reflect the aggregate (and maximum) compensation expense that will be recognized assuming the service period of the awards (determined in accordance with FASB ASC Topic 718) is satisfied.

(5) The breakdown of All Other Compensation and explanatory notes are as follows:

Name	Year	Distributions[(a)]	Living Expenses[(b)]	Moving Expenses[(b)]	Company 401(k) Match	Insurance Gross-Up	Severance	PTO Payment
Michael J. Bradley	2010		10,701					
Byron R. Kelley	2010	208,980	54,000	14,329	16,500	858		47,233
Thomas E. Long	2010		3,157	8,473				
A. Troy Sturrock	2010	15,724			9,482	529		
Stephen L. Arata	2010	45,094			14,595	642		34,050
Paul M. Jolas	2010	31,076			16,500	930		
Dennie W. Dixon	2010	28,050			11,924	667		
David G. Marrs	2010	39,457			8,308	335	300,000	13,211
L. Patrick Giroir	2010	42,424	16,923		4,366	367		23,877

(a) Distributions are amounts paid to Messrs. Kelley, Sturrock, Aratra, Jolas, Dixon, Marrs and Giroir related to awards of restricted units made under our LTIP in 2010 or in prior years.

(b) Other than living and moving expenses provided to Messrs. Bradley, Kelley, Long and Giroir, as described above, the Partnership did not provide perquisites or other personal benefits to any Named Executive Officer exceeding $10,000.

Grant of Plan-Based Awards

The following table provides information concerning each grant to our NEOs in the year ended December 31, 2010.

Grants of Plan-Based Awards

for the Year Ended December 31, 2010

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards				
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**All Other Stock Awards Number of Shares of Stock or Units (#)**	**Grant Date Fair Value of Stock and Option Awards ($)[(1)]**
Michael J. Bradley[(2)]	11/22/2010							50,000	1,222,500
	12/17/2010							50,000	1,225,000
Byron R. Kelley[(3)]	05/07/2010	252,000	554,400	902,160	12,000	24,000	36,000	16,000	330,400
	11/22/2010							33,000	806,850
Thomas E. Long[(2)]	12/01/2010							15,000	390,000
	12/17/2010							23,500	575,750
A. Troy Sturrock	05/07/2010	36,500	80,300	130,524	1,050	2,100	3,150	1,400	28,910
	12/17/2010							10,000	245,000
Stephen L. Arata[(4)(5)]	05/07/2010	106,238	233,723	380,330	4,200	8,400	12,600	5,600	115,640
Paul M. Jolas	05/07/2010	135,000	297,000	482,760	5,100	10,200	15,300	6,800	140,420
	12/17/2010							23,500	575,750
Dennie Dixon[(4)]	05/07/2010	80,738	177,623	288,717	2,100	4,200	6,300	2,800	57,820
David Marrs[(4)]	05/07/2010	135,000	297,000	483,300	4,350	8,700	13,050	5,800	119,770
L. Patrick Giroir[(4)(5)]	05/07/2010	88,688	195,113	317,501	4,050	8,100	12,150	5,400	11,510

(1) The amount shown in the column entitled Grant Date Fair Value of Stock and Option Awards reflects the grant date fair value, computed in accordance with FASB ASC Topic 718.

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(2) Messrs. Bradley and Long were ineligible for bonus awards in 2010.

(3) The threshold, target and maximum amounts shown for Mr. Kelley under the column entitled Estimated Future Payouts Under Non-Equity Incentive Plan Awards are for illustration purposes only. Upon his resignation and retirement, Mr. Kelley received a bonus of $856,800. The 16,000 time-based phantom units and the 24,000 performance-based phantom units granted to Mr. Kelley received accelerated vesting on the effective date of his resignation and retirement. The performance-based vesting units were accelerated at 100% of target performance. Please see Potential Payments upon a Termination or Change of Control Separation Agreement, Release and Consulting Agreement with Byron R. Kelley below for additional information.

(4) The threshold, target and maximum amounts shown for Messrs. Arata, Dixon, Marrs and Giroir under the column entitled Estimated Future Payouts Under Non-Equity Incentive Plan Awards, are for illustration purposes only, as these individuals were ineligible to receive bonus awards in 2010 due to their tendered or expected resignations.

(5) Units shown under the columns entitled Estimated Future Payouts Under Equity Incentive Plan Awards, and All Other Stock Awards for Messrs. Arata and Giroir were forfeited upon their respective resignations.

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

The following is a discussion of material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and the Grants of Plan-Based Awards Table for 2010.

Employment, Incentive Compensation and Non-Compete Agreements

Byron R. Kelley: Effective as of April 1, 2008, Regency GP LLC entered into an employment agreement with Byron R. Kelly. The agreement was to terminate on April 1, 2010, subject to automatic additional one-year extensions until either the Partnership or Mr. Kelley gave at least one-year s prior written notice of non-renewal. Mr. Kelley s employment agreement was automatically extended for one additional year on April 1, 2010. Mr. Kelley s annual base salary was $489,250, subject to increases by the Committee and a monthly living allowance of $4,500. On October 19, 2010, the Committee elected to increase Mr. Kelley s base salary to $504,000, effective July 5, 2010. Under the employment agreement, Mr. Kelley was eligible to participate in the annual bonus plan, and had a target bonus equal to his annual base salary. In connection with Mr. Kelley s retirement and resignation, however, we entered into a Separation Agreement, Release and Consulting Agreement with Mr. Kelley that, except with respect to certain confidentiality, non-competition and non-solicitation provisions, terminated Mr. Kelley s employment agreement. Mr. Kelley s Separation Agreement, Release and Consulting Agreement is described below in the section titled Potential Payments upon a Termination or Change of Control.

David G. Marrs: On September 1, 2009, Regency GP LLC amended and restated its employment agreement with David Marrs, pursuant to which Mr. Marrs was promoted to Division President of the Contract Compression Operations, and President of CDM. Under the terms of the agreement, Mr. Marrs base salary was $300,000, subject to annual reviews and increases by the Committee, and he was eligible for an annual performance bonus of up to 90 percent of his base salary. Effective June 8, 2010, the agreement was terminated. We entered into a Separation Agreement and Release with Mr. Marrs that is described below in the section titled Potential Payments upon a Termination or Change of Control.

We do not maintain employment agreements with any of the remaining Named Executive Officers.

Phantom Units

Awards reported for 2010 in the Stock Awards column of the Summary Compensation Table reflect awards of phantom units.[1] Each phantom unit represents a contractual right to receive one common unit or the fair market value of one common unit, as determined by the Committee in its discretion. The awards of phantom units granted to our Named Executive Officers during fiscal 2010 are subject to restrictions that lapse according to the passage of time or the achievement of certain performance measures relative to our peer companies.

1 The dollar amount shown in the Summary Compensation Table for the year ended December 31, 2009 for Dennie Dixon includes a grant of 15,000 restricted units, which were awarded to Mr. Dixon as part of salary negotiations.

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For equity awards granted in May 2010, 40 percent of the phantom units were subject to restrictions that lapse according to the passage of time, and 60 percent were subject to restrictions that lapse based upon the Partnership s achievement of certain levels of TUR, as compared to its peers. As described in more detail in the section entitled Potential Payouts upon a Termination or Change of Control, certain of the awards granted to NEOs in May 2010 received accelerated vesting or were forfeited pursuant to the Change of Control. Phantom units granted in May 2010 participate in distributions on the same basis as other common units, but the holder is not entitled to payment of those distributions until the holder s right to the underlying unit vests.

The grants of phantom units made in December 2010 vest as to 20 percent of the award on each of the first five anniversaries of the grant date. Phantom units granted in December 2010 receive distributions on the same basis as our other unitholders, regardless of whether the right to the underlying unit has vested.

Vesting provisions applicable to awards granted to our NEOs are discussed more fully below in the section entitled Potential Payouts upon a Termination or Change of Control Termination of Employment or Change of Control under our LTIP. The Named Executive Officer does not have the right to sell or dispose of unvested phantom units, and unvested units are forfeited at the time the holder terminates employment. If the Named Executive Officer forfeits the right to the underlying unit, he also forfeits the right to any distributions made.

For additional information regarding the terms applicable to grants of phantom units made in 2010, please see the narrative above entitled Compensation Discussion and Analysis Compensation Components and Analysis Equity Based Awards and Potential Payments upon a Termination or Change of Control.

Options

We did not grant any options to purchase common units during fiscal year 2010.

All Other Compensation

Please see the Compensation Discussion and Analysis above for a discussion of any perquisites paid to our Named Executive Officers, and the section below entitled Potential Payments Upon a Termination or Change of Control for a discussion of payments made upon resignation.

Description of Plan-Based Awards

The terms of the non-equity incentive plan awards reflected in the Summary Compensation Table and of the Grants of Plan-Based Awards Table under the columns headed Estimated Future Payouts Under Non-Equity Incentive Plan Awards are described in the Compensation Discussion and Analysis above.

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Salary and Cash Incentive Awards in Proportion to Total Compensation

The following table sets forth the percentage of each Named Executive Officer s total compensation that we paid in the form of salary and bonus.

Name	Percentage of Total Compensation
Michael J. Bradley	2%
Byron R. Kelley	40%
Thomas E. Long	2%
A. Troy Sturrock	44%
Stephen L. Arata	36%
Paul M. Jolas	39%
Dennie W. Dixon	57%
David G. Marrs	27%
L. Patrick Giroir	24%

Outstanding Equity Awards at December 31, 2010

The following table provides information concerning common units that have not vested for our Named Executive Officers.

		Stock Awards			
Name	Grant Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested[9] ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested[(1)(8)] ($)
Michael J. Bradley	11/22/2010	50,000[(2)]	1,363,000		
	12/17/2010	50,000[(3)]	1,363,000		
Byron R. Kelley	11/21/2010	33,000[(4)]	899,580		
Thomas E. Long	12/1/2010	15,000[(5)]	408,900		
	12/17/2010	23,500[(3)]	640,610		
A. Troy Sturrock	05/07/2010	1,400[(6)]	38,164	2,100[(7)]	57,246
	12/17/2010	10,000[(3)]	272,600		
Stephen L. Arata					
Paul M. Jolas	05/07/2010	6,800[(6)]	185,368	10,200[(7)]	278,052
	12/17/2010	23,500[(3)]	640,610		
Dennie W. Dixon	05/07/2010	2,800[(6)]	76,328	4,200[(7)]	114,492
David Marrs	05/07/2010			267[(7)]	7,278
L. Patrick Giroir					

(1) The market value of outstanding equity awards was calculated using the closing price of $27.26 on December 31, 2010.

(2) The forfeiture restrictions on these time-based phantom unit awards lapse as to 20 percent of the award on each of the first five anniversaries of November 2, 2010.

(3) The forfeiture restrictions on these time-based phantom unit awards lapse as to 20 percent of the award on each of the first five anniversaries of December 5, 2010.

(4) The forfeiture restrictions on these time-based phantom unit awards lapse as to 33 and $^{1}/3$ percent of the award on each of the first three anniversaries of November 22, 2010.

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(5) The forfeiture restrictions on these time-based phantom unit awards lapse as to 20 percent of the award on each of the first five anniversaries of December 1, 2010.
(6) The forfeiture restrictions on these time-based phantom unit awards lapse as to 33 and 1/3 percent of the award on each of the first three anniversaries of March 15, 2010.
(7) 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, as described above in Compensation Discussion and Analysis Compensation Components and Analysis Equity Based Awards.
(8) The market value for unvested unit awards granted to our Named Executive Officers includes the following amounts attributable to accrued and unpaid distributions related to phantom units awarded to the Named Executive Officer, where the right to the phantom units has not yet vested:

Name	Accrued and Unpaid Distributions ($)	Equity Incentive Plan Awards: Accrued and Unpaid Distributions ($)
Michael Bradley		
Byron R. Kelley		
Thomas E. Long		
A. Troy Sturrock	1,869	2,804
Stephen L. Arata		
Paul M. Jolas	9,078	13,617
Dennie W. Dixon	3,738	5,607
David G. Marrs		356
L. Patrick Giroir		

The following table provides information relating to the vesting of unit awards during 2010 for each of our Named Executive Officers.

Option Exercises and Stock Vested for the Year Ended December 31, 2010

	Option Awards		Unit Awards	
Name	Number of units acquired on exercise (#)	Value Realized on Exercise ($)(1)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting(2)
Michael Bradley				
Byron R. Kelley			122,671	4,256,717
Thomas E. Long				
A. Troy Sturrock			8,415	255,609
Stephen L. Arata	35,000	175,977	19,122	577,434
Paul M. Jolas			18,019	543,659
Dennie W. Dixon			19,672	564,686
David G. Marrs			24,719	780,177
L. Patrick Giroir			25,986	785,648

(1) The value realized on exercise represents the difference between the closing price of the units on the exercise date and the exercise price, multiplied by the number of units underlying each option exercised.
(2) The value realized upon vesting represents the product of the number of units vested and the closing price of the units on the vesting date.

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Potential Payments upon a Termination or Change of Control

We previously maintained certain employment agreements and we maintain severance agreements that provide our executives with post-termination payments, and our equity award agreements under our LTIP contain accelerated vesting provisions upon a termination of employment in certain circumstances. We believe that these provisions create important retention tools for us, as providing for accelerated vesting of equity awards upon a termination of employment in connection with a change in control provides employees with value in the event of a termination of employment that was beyond their control. In addition, we believe that it is important to provide the Named Executive Officers with a sense of stability, both in the midst of transactions that may create uncertainty regarding their future employment and post-termination as they seek future employment. We believe post-termination payments allow management to focus their attention and energy on making the best objective business decisions that are in the interest of the Partnership without allowing personal considerations to cloud the decision-making process. Further, we believe that such protections maximize unitholder value by encouraging the Named Executive Officers to review objectively any proposed transaction in determining whether such proposal or termination is in the best interest of our unitholders, whether or not the executive will continue to be employed. Executive officers at other companies in our industry and the general market where we compete for executive talent commonly have equity compensation plans that provide for accelerated vesting upon certain events in connection with a change of control and post-termination payments, and we have consistently provided this benefit to our Named Executive Officers in order to remain competitive in attracting and retaining skilled professionals in our industry.

Separation Agreement, Release and Consulting Agreement with Byron R. Kelley.

The employment agreement we maintained with Byron Kelley was terminated upon his resignation and retirement in November 2010. We entered into a Separation Agreement, Release and Consulting Agreement with Mr. Kelley on November 5, 2010 (the Separation Agreement) that mutually terminated Mr. Kelley s employment with us as of November 21, 2010, and replaced all severance obligations that were contained in Mr. Kelley s employment agreement. Mr. Kelley is entitled to receive a cash payment in the amount of $1,864,800, less deductions for taxes and withholdings, which represented his base salary amount for a period of two years as well as his bonus payment for the 2010 year. This cash payment will be made to him in May of 2011 in order to comply with the requirements of Section 409A of the Internal Revenue Code of 1986, which require us to delay the payment for a six month period following his resignation due to Mr. Kelley s status as a key employee at the end of his employment with us. Mr. Kelley s unvested 16,000 time-based phantom units and 24,000 performance-based phantom units that were granted to him on May 7, 2010 received accelerated vesting on the effective date of his resignation and retirement; all performance-based phantom units were accelerated at 100 percent of target performance levels. Mr. Kelley also received a payment in the amount of $53,400 which represented accrued distributions with respect to the phantom units that vested as a result of acceleration concurrent with his retirement and resignation. Mr. Kelley signed a general release in our favor in exchange for the consideration he received pursuant to the Separation Agreement, and we agreed to release Mr. Kelley from all claims and causes of action we might have against him with respect to his employment with us.

Pursuant to his execution of the Separation Agreement, Mr. Kelley also affirmed his obligations under his original employment agreement regarding confidentiality and non-competition and non-solicitation restrictions, although the restricted period will be decreased from two years in the original employment agreement to one year.

Mr. Kelley will provide us with consulting services for a period of three years following the effective date of his resignation on November 21, 2010. In consideration for Mr. Kelley s consulting services, he received a grant of 33,000 time-based phantom units that will vest in three equal annual installments over the term of the consulting period. Distributions will be paid to Mr. Kelley on a quarterly basis with respect to the phantom units granted to him in connection with his consulting service.

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Separation Agreement and Release with David Marrs.

As described briefly above, the employment agreement we maintained with David Marrs was terminated, effective June 8, 2010. In connection with his termination of employment, Mr. Marrs, after executing a Separation Agreement and Release that included a full and general release in our favor, received a lump sum payment equal to $300,000, less deductions for taxes and other applicable withholdings, which, pursuant to the terms of his previous employment agreement, was equal to one year s base salary, a pro-rated bonus payment, and the continuation of medical coverage for 36 months (the first 18 months being a reimbursement of the Consolidated Omnibus Budget Reconciliation Act (COBRA) costs, and the remaining 18 months being a reimbursement for health insurance obtained by Mr. Marrs that does not exceed the monthly COBRA premium costs for the previous 18 months). Mr. Marrs also received full vesting for all time-based equity awards then outstanding, and his outstanding performance-based equity awards vested pro rata (based upon the number of days that had lapsed in the performance period as of his termination of employment compared to the number of total days in the performance period). As a result of his accelerated equity vesting, Mr. Marrs also received a payment equal to $2,581, less deductions for taxes and other applicable withholdings, which represented payment for accumulated DERs associated with the vesting of 5,800 service-based phantom units.

After the term of his employment, Mr. Marrs may not disclose our confidential information and may not use such information for his own benefit nor for the benefit of any other party than us. Mr. Marrs is subject to a non-compete period of one year following his termination of employment and a non-solicitation period of three years. We have also entered into a non-disparagement covenant with Mr. Marrs, where Mr. Marrs agrees not to disparage us in public or private statements of any form, which applies following his termination of employment.

Severance Agreement with Paul M. Jolas.

The severance agreement we maintain with Paul M. Jolas provides for severance payments in the event that we terminate him, within two years of September 8, 2009 (the effective date of the severance agreement), without cause or he terminates his employment for good reason within six months following a change of control (all as defined in the agreement). With respect to a good reason termination, Mr. Jolas must execute a comprehensive release of claims within 30 days of his termination. If Mr. Jolas termination satisfies either of the above conditions, he will receive one year s base salary (excluding any bonuses or other incentive compensation), as determined on the date his employment terminates. Payment must be made in one lump sum, less withholding for applicable taxes and other deductions, within 30 days of the date on which Mr. Jolas executes the release.

In the event that Mr. Jolas employment terminates for any other reason, he is not entitled to severance payments. Mr. Jolas termination for cause shall mean: (i) failure to render his 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; (vi) unlawful use or possession of illegal drugs on Partnership premises or while performing duties and responsibilities for the Partnership; or (vii) death or inability to perform, with or without reasonable accommodation, the essential functions of his position for a total of 3 months during any 6 month period as a result of incapacity due to mental or physical illness. A good reason termination may occur upon a material reduction in the nature or scope of Mr. Jolas authority, duties or responsibilities, material reduction of his base salary, or our requirement that he relocates his principal residence to a location more than 50 miles from its location as of the date of the severance agreement. A change of control generally will be deemed to occur upon the (i) closing of a sale which results in our General Partner s members or equity owners holding less than 50 percent of the securities or the voting power of our General Partner or an applicable surviving entity following that sale, (ii) sale, lease, exchange or other transfer of our General Partner s assets or substantially all of its assets, or (iii) dissolution or liquidation of our General Partner.

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Special Severance and Separation Agreement and Full Release of Claims Agreements with Dennie W. Dixon.

The Special Severance Agreement we maintained with Dennie W. Dixon as of December 31, 2010 provided for a special severance payment, in consideration for Mr. Dixon s continued employment with the Partnership from October 11, 2010 (the effective date under the Special Severance Agreement) through the termination date (January 10, 2011), during which time the Partnership was undergoing a reorganization. After the term of his employment, Mr. Dixon may not disclose our confidential information and will not use such information for his own benefit nor for the benefit of any other party than us. We have also entered into a non-disparagement covenant with Mr. Dixon, where Mr. Dixon agrees not to disparage us in public or private statements of any form.

We also entered into a Separation Agreement and Full Release of Claims agreement with Mr. Dixon on January 10, 2011 (the Separation Agreement). The agreement provided for a severance payment following Mr. Dixon s termination on January 10, 2011 (the termination date under the Separation Agreement). In connection with his termination of employment, Mr. Dixon, after executing a full and general release in our favor, received a lump sum payment equal to $161,500, less deductions for taxes and other applicable withholdings. In addition, as further consideration, Mr. Dixon will also receive a pro-rated bonus payment (assuming it has not already been paid as of the payment date), and continuation of medical coverage for nine months pursuant to COBRA, and we will pay for the full cost of Mr. Dixon s premium. Mr. Dixon will not at any time use, disseminate or disclose any of our confidential information to any person or entity either during the remainder of his employment term or following his employment.

With respect to Mr. Dixon s outstanding equity awards at the time of his termination, the time-based phantom units he held as of January 10, 2011 were accelerated, while the performance-based phantom units were accelerated assuming a 150 percent performance target. Using the closing price of our common stock on January 10, 2011 of $27.48, the amounts Mr. Dixon received with respect to his awards were $76,944 for the time-based phantom units, and $173,124 for his performance-based phantom units.

Arrangements with Messrs. Bradley, Long and Sturrock

We do not maintain individual employment, severance or retention agreements with Messrs. Bradley, Long and Sturrock that provide for severance payments or change of control payments. Mr. Sturrock received a grant of phantom units on May 7, 2010 that will receive accelerated vesting upon certain terminations of employment as described in further detail below. Messrs. Bradley and Long received grants of phantom units in November and December 2010 that will also be entitled to accelerated vesting in certain situations, as described in greater detail below.

Arrangements with Messrs. Giroir and Arata.

Mr. Giroir s resignation was effective as of June 11, 2010 and Mr. Arata s resignation was effective as of September 4, 2010. Messrs. Giroir and Arata did not have individual employment agreements that provided for severance or change of control payments. Each of the executives held unvested phantom units at the time of his termination of employment, under the terms of the award agreements, the phantom units were forfeited without payment.

Termination of Employment or Change of Control Under our LTIP.

Both the May and December 2010 equity-based compensation awards were granted under our LTIP. The awards made to our NEOs in May 2010 contain provisions that provide for the awards (or certain portions of the awards) to receive accelerated vesting upon a termination without cause or for good reason that is in connection with a change of control, or the death or disability of the executive (each term as defined below).

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Unless an executive s employment agreement states otherwise, all other terminations will require a forfeiture of any unvested unit awards. Generally, upon a termination of employment due to death or disability, the May 2010 awards subject to time-based vesting will receive full acceleration, while the awards subject to performance conditions will accelerate in a pro-rata manner based upon the point in time the vesting occurs during the performance period. For the 2010 performance-based phantom unit grants, the performance period is May 7, 2010 through March 15, 2013.

The agreements that govern the performance-based phantom awards granted to our executives on May 7, 2010 state that if the executive is terminated without cause or resigns with good reason within the 12-month period following a change of control and prior to the end of the performance period, the awards automatically become vested at the maximum vested percentage of 150 percent of target.

The November and December 2010 phantom unit grants also provide for accelerated vesting upon the executive s death or disability, but the grants differ from the May 2010 grants in that they also accelerate upon our change of control, and they do not accelerate in connection with a good reason or a without cause termination of the executive.

A termination for cause under the phantom award agreements, as applicable, will generally be defined by using the definition of such term described above within Mr. Jolas severance agreement. 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 the LTIP 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.

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Potential Payments Upon a Termination or Change of Control Table

The following table quantifies the amounts that each current NEO would be entitled to receive upon a termination of employment or a change of control, as applicable, assuming that such event occurred on December 31, 2010. For all NEOs that separated from service during the 2010 year, the payments and benefits that they actually received have been described above. The precise amount that any NEO would receive cannot be determined with any certainty until an actual termination or change of control has occurred, or until the completion of certain equity awards applicable performance period, but the following are our best estimates as to the amounts that the current NEOs are entitled to as of December 31, 2010, and using our closing stock price on that date of $27.26. We have assumed for purposes of this table that all salary and reimbursable expenses were current, and that no vacation had accrued as of December 31, 2010.

Executive	Change of Control	Termination of Employment for Death or Disability	Retirement	Termination of Employment Without Cause or for Good Reason
Michael J. Bradley				
Accelerated Equity(1)	$ 2,726,000	$ 2,726,000	$	$
Total	2,726,000	2,726,000		
Thomas E. Long				
Accelerated Equity(1)	$ 1,049,510	$ 1,049,510	$	$
Total	1,049,510	1,049,510		
A. Troy Sturrock				
Accelerated Equity(1)	$ 272,600	$ 323,827	$	$ 57,758
Total	272,600	323,827		57,758
Paul M. Jolas				
Severance Payment(2)	$	$	$	$ 360,000
Accelerated Equity(1)	640,610	889,426		921,150
Total	640,610	889,426		1,281,150

(1) Amounts were calculated by multiplying the number of each time-based units the executive held on December 31, 2010 by our closing stock price of $27.26.

Performance-based Units. Pursuant to the May 2010 award agreements, we estimated a pro-rata acceleration of performance-based phantom units by multiplying the number of such outstanding units (2,100 for Mr. Sturrock; and 10,200 for Mr. Jolas) by a fraction (238/1043, or the number of days which had lapsed in the performance period as of December 31, 2010 over the full number of days in the performance period), and then multiplied this number by $27.26. For termination events requiring pro-rata acceleration of the performance-based units, the vesting could not occur until the end of the original performance period, or March 15, 2013, and we have assumed solely for purposes of this disclosure that the performance goals would have been met at target, or 100 percent vesting at our December 31, 2010 stock price. For a termination for cause or good reason in the 12-month period following a change of control during the performance period, however, executives would be considered automatically vested at maximum at a rate of 150 percent for the performance-based units, and the amounts attributable to the performance-based units in the last column above are multiplied by 150 percent.

(2) This amount is Mr. Jolas base salary at December 31, 2010 year ($360,000).

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Directors Compensation

Our Board of Directors annually determines the amounts payable to the members of our Board of Directors. In 2010, 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 and $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 Committee receives an annual fee of $10,000.

Name	Fees Earned or Paid in Cash ($)
Michael Bradley	68,000
Jim Bryant	17,000
Rodney L. Gray	67,500
John D. Harkey, Jr.	12,000
John W. McReynolds	
John Mills	46,000
James Burgoyne (1)	25,500
Daniel Castagnola (1)	26,500
Paul Halas (1)	27,000
Mark Mellana (1)	29,500
Brian Ward (1)	26,500

(1) Messrs. Burgoyne, Castagnola, Halas, Mellana and Ward are officers of GE EFS, a related party. All fees paid to these directors were remitted directly to GE EFS.

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 fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation. For our unit-based compensation arrangements, we record compensation expense over the vesting period of the awards, as discussed further in Note 17 to our audited consolidated financial statements.

Relationship Between Compensation Policies and Risk Management

The Committee analyzed whether our compensation programs are structured in a way that promotes excessive risk-taking by our employees and concluded that our programs are appropriately structured to mitigate risk, and are therefore not likely to result in a material adverse effect on the Partnership. The Committee s evaluation covered a range of practices and policies regarding compensation, including: the funding of the bonus pool allocable to business segments based upon both company-wide performance metrics and performance metrics specific to each business group, the balance between short- and long-term incentives, the discretionary nature of individual awards, and vesting conditions applicable to grants of equity awards that align employees interests with unitholders interests. In addition, our Committee and the Board retain the ability to eliminate incentive bonuses based on the financial performance of the Partnership. We believe that each of these factors reduces the likelihood that performance results in any one year could be distorted to enhance payments under our compensation plans.

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

The following table sets forth, as of February 10, 2011, the beneficial ownership of our units by:

each person who then owned beneficially five percent or more of our common units;

each member of the Board of Directors of Regency GP LLC;

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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.

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	19.1%
Regency LP Acquirer, L.P., General Electric Capital Corporation, General Electric Company (2)	800 Long Ridge Rd Stamford, CT 06927	15,277,106	11.1%
Tortoise Capital Advisors, L.L.C. (3)	11550 Ash Street, Suite 300 Leawood, KS 66211	8,637,562	6.3%
Neuberger Berman Group LLC	605 Third Avenue New York, NY 10158	8,507,898	6.2%
Michael J. Bradley		5,000	*
Thomas E. Long		-	*
A. Troy Sturrock		14,692	*
Paul M. Jolas		20,685	*
James W. Bryant		-	*
Rodney L. Gray		5,000	*
John D. Harkey, Jr.		-	*
John W. McReynolds		-	*
Byron R. Kelley		131,921	0.1%
Stephen L. Arata		-	*
Dennie M. Dixon		6,692	*
David G. Marrs		-	*
L. Patrick Giroir		-	*
All directors and executive officers as a group (13 persons)		183,990	0.1%
Total number of units as of February 10, 2011		137,295,308	

(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 13D/A filed with the SEC on December 9, 2010, GE, GECC and Regency LP Acquirer, L.P. (LP Holdings) are the beneficial owners of 15,277,106 common units. LP Holdings is the sole record owner of, and has the sole power to vote and dispose of, 15,277,106 common units. Neither GECC nor GE directly own any common units. GE and GECC may be deemed beneficial owners of, and

may each be deemed to possess sole voting and dispositive powers with respect to, 15,277,106 common units due to their indirect ownership interests in LP Holdings.

(3) Tortoise Capital Advisors, L.L.C. (TCA) acts as an investment adviser to certain closed-end investment companies registered or regulated 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 advisor 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 8,637,562 common units reported as beneficially owned by TCA, TCA has reported that it has shared voting power with respect to 8,073,510 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 the Schedule 13G filed by TCA with the SEC on February 11, 2011.

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 the LTIP plan as of December 31, 2010.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Plans (Excluding Securities Reflected in Column[(a)]) (c)
Equity compensation Plans Approved by Security holders		$	
Equity compensation plans not approved by security holders			
Long-Term Incentive Plan[(1)]	944,467*	$ 23.25	363,333
Total	944,467	$ 23.25	363,333

* Assumes performance-based phantom unit grants vest at 100 percent.

(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 3,565,584 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

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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 the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The partnership agreement of the Partnership provides that any matter approved by the Conflicts Committee will be deemed approved by all partners of the Partnership and not a breach by the General Partner or its affiliates of the partnership agreement or of any duty they may owe the Partnership 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, 2010, ETE owned approximately 19 percent of our outstanding common units.

On May 26, 2010, we entered into a services agreement with ETE and Services Co. Under the services agreement, Services Co. provides certain general and administrative services to us. We will pay Services Co. s direct expenses for these services, plus an annual fee of $10,000,000, and will receive the benefit of any cost savings recognized for these services. The services agreement has a five year term, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for us or upon an event of default. We paid ETE service fees of $5,833,000 in 2010.

On May 26, 2010, we purchased from ETE a 49.9 percent interest in MEP and an option to acquire an additional 0.1 percent interest in MEP that is exercisable on May 27, 2011. In return, we issued 26,266,791 common units, valued at $584,436,000, to ETE in a private placement, relying on Section 4(2) of the Securities Act and received a working capital adjustment of $4,632,000.

Our Contract Compression segment provides contract compression services to ETE and recorded $1,102,000 in revenues in 2010 in gathering, transportation and other fees on the statement of operations.

In conjunction with our distributions to the limited and general partner interests, ETE received cash distributions, including IDRs, of $27,716,000 in 2010.

Until May 26, 2010, GE owned 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. As of December 31, 2010, GE owned approximately 11 percent of our outstanding common units.

On April 30, 2010, we purchased an additional 6.99 percent general partner interest in HPC from EFS Haynesville, an affiliate of GE, for $92,087,000, bringing our total general partner interest in HPC to 49.99 percent. We also entered into a voting agreement that grants us the right to vote the general partner interest in HPC retained by EFS Haynesville.

In conjunction with our distributions to the limited and general partner interests, GE received cash distributions, including IDRs, of $44,022,000 in 2010.

Item 14. Principal Accountant Fees and Services

Appointment of Independent Registered Public Accountant. The Audit Committee retained KPMG LLP as our principal accountant to conduct the audit of our financial statements for the years ended December 31, 2010 and 2009.

Audit Fees. The following table sets forth fees billed by KPMG LLP for the professional services rendered for the audits of our annual financial statements and other services rendered for the years ended December 31, 2010 and 2009.

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	December 31, 2010	December 31, 2009
	(in thousands)	
Audit fees[(1)]	$ 2,101	$ 1,940
Audit related fees[(2)]	10	68
Total	$ 2,111	$ 2,008

(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.

(2) Includes fees related to consultation concerning financial accounting and reporting standards.

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 Committee, the Audit Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit 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 Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountant. The policy requires that all services provided by KPMG LLP, including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee.

The Audit 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.

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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.

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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	February 18, 2011
/s/ THOMAS E. LONG **Thomas E. Long**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 18, 2011
/s/ A. TROY STURROCK **A. Troy Sturrock**	Vice President, Controller (Principal Accounting Officer)	February 18, 2011
/s/ JAMES W. BRYANT **James W. Bryant**	Director	February 18, 2011
/s/ RODNEY L. GRAY **Rodney L. Gray**	Director	February 18, 2011
/s/ JOHN D. HARKEY, JR. **John D. Harkey, Jr.**	Chairman of the Board of Directors	February 18, 2011
/s/ JOHN W. MCREYNOLDS **John W. McReynolds**	Director	February 18, 2011

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Index to Exhibits

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
2.1	Agreement and Plan of Merger among CDM Resource Management, Ltd., the Partners thereof, as listed on the signature pages hereof, Regency Energy Partners LP and ADJHR, LLC dated as of December 11, 2007	8-K	December 11, 2007
2.2	Contribution Agreement by and among Regency Energy Partners LP, Regency Gas Services LP, as Buyer, and ASC Hugoton LLC and FrontStreet EnergyOne LLC as Sellers dated December 10, 2007 and joined in by Aircraft Services Corporation (solely for purposes of Section 2.3(g) hereof)	8-K	December 10, 2007
2.3	Agreement and Plan of Merger among Nexus Gas Partners, LLC, Nexus Gas Holdings, LLC, Regency Energy Partners LP and Regency NX, LLC	8-K	March 26, 2008
2.4	Contribution Agreement, dated as of February 26, 2009, by and among Regency Haynesville Intrastate Gas LLC, a Delaware limited liability company and a wholly-owned indirect subsidiary of Regency Energy Partners LP, General Electric Capital Corporation, a Delaware corporation and an affiliate of GE Energy Financial Services, 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
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

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
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 $^{3}/8$ percent Senior Notes due 2016, together with the global notes	10-Q	August 10, 2009
4.3	Registration Rights Agreement for 9 $^{3}/8$ percent Senior Notes due 2016	10-Q	August 10, 2009
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 between Regency GP 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		
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

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
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 Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Restricted Unit Grant	S-1	333-128332
10.4	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Phantom Unit Grant (With DERS)	S-1	333-128332
10.5	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Phantom Unit Grant (Without DERS)	S-1	333-128332
10.6	Form of Contribution, Conveyance and Assumption Agreement	S-1	333-128332
10.7	Amended Executive Employment Agreement dated November 24, 2008 between the Registrant and Byron R. Kelley	10-K	March 2, 2009
10.8	Severance Agreement with Dan A. Fleckman	10-Q	May 12, 2008
10.9	Amended Executive Employment Agreement dated January 15, 2008 between the Registrant and Randall Dean	10-K	March 2, 2009
10.10	Form of Indemnification Agreement between Regency GP LLC and Indemnities	S-1	333-128332
10.11	Form of Omnibus Agreement	S-1	333-128332
10.12	Master Lease Agreement between Caterpillar Financial Services Corporation and CDM Resource Management LLC, dated as of February 26, 2009	10-K	March 2, 2009
10.12.1	Amendment No. 1 to Master Lease Agreement between Caterpillar Financial Services Corporation and CDM Resource Management LLC, dated as of May 20, 2009	10-Q	August 10, 2009
10.13	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
10.14	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
10.15	Pipeline Construction Contract, dated as of February 24, 2009, by and between Regency Intrastate Gas LP and Price Gregory International, Inc.	8-K	March 18, 2009
10.16	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

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
10.17	Assignment and Assumption Agreement, dated September 2, 2009, by and between EFS Haynesville, LLC and Regency Haynesville Intrastate Gas LLC	8-K	September 4, 2009
10.18	Consulting Agreement with Randall Dean dated as of September 1, 2009	10-Q	November 9, 2009
10.19	Employment Agreement with David Marrs dated as of September 1, 2009	10-Q	November 9, 2009
10.20	Severance Agreement with Paul Jolas dated as of September 8, 2009	10-Q	November 9, 2009
10.21	Fifth Amended and Restated Credit Agreement, dated March 4, 2010	8-K	March 4, 2010
10.22	Amendment Agreement to the Fifth Amended and Restated Credit Agreement, dated March 4, 2010	8-K	March 4, 2010
10.23	Assignment and Assumption Agreement, dated April 30, 2010, by and between EFS Haynesville, LLC and Regency Haynesville Intrastate Gas LLC	8-K	April 30, 2010
10.24	Voting Agreement, dated April 30, 2010, by and between EFS Haynesville, LLC and Regency Haynesville Intrastate Gas LLC	8-K	April 30, 2010
10.25	Contribution Agreement, dated May 10, 2010, by and among Energy Transfer Equity, L.P., Regency Energy Partners LP and Regency Midcontinent Express LLC	8-K	May 11, 2010
10.26	Form of Grant of Phantom Units Service Vesting	8-K	May 11, 2010
10.27	Form of Grant of Phantom Units Performance Vesting	8-K	May 11, 2010
10.28	Amendment Agreement No. 1 to Fifth Amended and Restated Credit Agreement	8-K	May 28, 2010
10.29	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
10.30	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
10.31	Merger Agreement by and among Zephyr Gas Management, LLC, Zephyr Gas Services, LP, Regency Gas Services Services LP, and Regency Zephyr LLC, dated August 6, 2010.	10-Q	August 9, 2010
10.32	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Phantom Unit Grant (With DERS)		
12.1	Computation of Ratio of Earnings to Fixed Charges		
21.1	List of Subsidiaries of Regency Energy Partners LP		
23.1	Consent of KPMG LLP		
23.2	Consent of KPMG LLP		
23.3	Consent of PricewaterhouseCoopers LLP		
31.1	Certifications pursuant to Rule 13a-14(a).		

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
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 Related to Potential Conflicts among Regency Energy Partners LP, Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P., dated as of August 10, 2010.	8-K	August 10, 2010
99.2	Audited Financial Statement 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.		
99.3	Audited Financial Statement of Midcontinent Express Pipeline LLC as of December 31, 2010 and for the seven month period ended December 31, 2010.		
99.4	Regency Energy Partner LP Notice of Beginning of Administrative Proceedings for Tax Year December 31, 2008.	10-K	March 1, 2010
99.5	Regency Energy Partner LP Notice of Beginning of Administrative Proceedings for Tax Year December 31, 2007.	10-K	March 1, 2010
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		

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Index to Consolidated Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners

Regency Energy Partners LP:

We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP and subsidiaries as of December 31, 2010 and 2009, and the related 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, the period from January 1, 2010 to May 25, 2010, and the years ended December 31, 2009 and 2008. 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 percent owned investee company which was acquired by the Partnership on May 26, 2010). The Partnership s investment in Midcontinent Express Pipeline LLC at December 31, 2010 was $652,482,000 and its 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 financial position of Regency Energy Partners LP and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for the period from May 26, 2010 to December 31, 2010, the period from January 1, 2010 to May 25, 2010, and the years ended December 31, 2009 and 2008, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Regency Energy Partners LP s internal control over financial reporting as of December 31, 2010, 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 February 18, 2011 expressed an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas

February 18, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners

Regency Energy Partners LP:

We have audited Regency Energy Partners LP and subsidiaries internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Regency Energy Partners LP 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 Annual 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Regency Energy Partners LP and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Regency Energy Partners LP acquired Zephyr Gas Services, LP on September 1, 2010, and management excluded from its assessment of the effectiveness of Regency Energy Partners LP s internal control over financial reporting as of December 31, 2010, Zephyr Gas Services, LP s internal control over financial reporting associated with total assets of $220,584,000 and total revenues of $13,662,000 included in the consolidated financial statements of Regency Energy Partners LP and subsidiaries at December 31, 2010 and for the period from September 1, 2010 to December 31, 2010. Our audit of internal control over financial reporting of Regency Energy Partners LP also excluded an evaluation of the internal control over financial reporting of Zephyr Gas Services, LP.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Regency Energy Partners LP and subsidiaries as of

December 31, 2010 and 2009, and the related 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, the period from January 1, 2010 to May 25, 2010, and the years ended December 31, 2009 and 2008, and our report dated February 18, 2011 expressed an unqualified opinion on those consolidated financial statements. We did not audit the financial statements of Midcontinent Express Pipeline LLC, (a 49.9 percent owned investee company which was acquired by the Partnership on May 26, 2010). The Partnership s investment in Midcontinent Express Pipeline LLC at December 31, 2010 was $652,482,000 and its 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.

/s/ KPMG LLP

Dallas, Texas

February 18, 2011

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Regency Energy Partners LP

Consolidated Balance Sheets

(in thousands except unit data)

	Successor December 31, 2010	Predecessor December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,400	$ 9,827
Restricted cash		1,511
Trade accounts receivable, net of allowance of $297 and $1,130	35,212	30,433
Accrued revenues	74,017	95,240
Related party receivables	32,342	6,222
Derivative assets	2,650	24,987
Other current assets	7,384	10,556
Total current assets	161,005	178,776
Property, Plant and Equipment:		
Gathering and transmission systems	543,286	465,959
Compression equipment	812,428	823,060
Gas plants and buildings	185,741	159,596
Other property, plant and equipment	81,295	162,433
Construction-in-progress	97,439	95,547
Total property, plant and equipment	1,720,189	1,706,595
Less accumulated depreciation	(59,971)	(250,160)
Property, plant and equipment, net	1,660,218	1,456,435
Other Assets:		
Investment in unconsolidated subsidiaries	1,351,256	453,120
Long-term derivative assets	23	207
Other, net of accumulated amortization of debt issuance costs of $3,326 and $10,743	37,758	19,468
Total other assets	1,389,037	472,795
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $15,584 and $33,929	770,155	197,294
Goodwill	789,789	228,114
Total intangible assets and goodwill	1,559,944	425,408
TOTAL ASSETS	$ 4,770,204	$ 2,533,414
LIABILITIES & PARTNERS CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 50,208	$ 44,912
Accrued cost of gas and liquids	80,756	76,657
Related party payables	3,338	2,312
Deferred revenues, including related party amounts of $8,765, and $338	25,257	11,292
Derivative liabilities	13,172	12,256
Escrow payable		1,511
Other current liabilities	23,419	12,368

Total current liabilities	196,150	161,308
Long-term derivative liabilities	61,127	48,903
Other long-term liabilities	6,521	14,183
Long-term debt, net	1,141,061	1,014,299
Commitments and contingencies		
Series A convertible redeemable preferred units, redemption amount of $83,891 and $83,891	70,943	51,711
Partners Capital and Noncontrolling Interest:		
Common units (138,255,919 and 94,243,886 units authorized; 137,281,336 and 93,188,353 units issued and outstanding at December 31, 2010 and December 31, 2009)	2,940,732	1,211,605
General partner interest	333,077	19,249
Accumulated other comprehensive loss	(11,099)	(1,994)
Total partners capital	3,262,710	1,228,860
Noncontrolling interest	31,692	14,150
Total partners capital and noncontrolling interest	3,294,402	1,243,010
TOTAL LIABILITIES AND PARTNERS CAPITAL AND NONCONTROLLING INTEREST	$ 4,770,204	$ 2,533,414

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Operations

(in thousands except unit data and per unit data)

	Successor	Predecessor		
	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
REVENUES				
Gas sales, including related party amounts of $3,298, $0, $0, and $0	$ 291,247	$ 228,097	$ 476,077	$ 1,115,037
NGL sales, including related party amounts of $136,960, $0, $0, and $0	238,076	152,803	239,255	378,618
Gathering, transportation and other fees, including related party amounts of $14,004, $12,200, $11,162 and $3,763	178,769	114,526	270,071	281,787
Net realized and unrealized (loss) gain from derivatives	(7,866)	(716)	37,712	(14,777)
Other, including related party amounts of $2,725, $0, $0, and $0	16,387	10,340	20,162	24,598
Total revenues	716,613	505,050	1,043,277	1,785,263
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $12,998, $6,564, $10,913, and $1,878	504,327	357,778	674,944	1,365,124
Operation and maintenance	77,808	47,842	117,080	119,715
General and administrative, including related party amounts of $5,833, $0, $0, and $0	43,739	37,212	57,863	51,323
Loss (gain) on asset sales, net	213	303	(133,282)	457
Management services ternination fee				3,888
Transaction expenses				1,620
Depreciation and amortization	75,967	41,784	100,098	93,393
Total operating costs and expenses	702,054	484,919	816,703	1,635,520
OPERATING INCOME	14,559	20,131	226,574	149,743
Income from unconsolidated subsidiaries	53,493	15,872	7,886	
Interest expense, net	(48,251)	(34,541)	(77,665)	(62,940)
Loss on debt refinancing, net	(15,748)	(1,780)		
Other income and deductions, net	(8,229)	(3,897)	(15,132)	328
(LOSS) INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(4,176)	(4,215)	141,663	87,131
Income tax expense (benefit)	552	404	(1,095)	(266)
(LOSS) INCOME FROM CONTINUING OPERATIONS	$ (4,728)	$ (4,619)	$ 142,758	$ 87,397
DISCONTINUED OPERATIONS				
Net (loss) income from operations of east Texas assets, including loss on disposal of $55 in 2010	(1,244)	(327)	(2,269)	13,931
NET (LOSS) INCOME	$ (5,972)	$ (4,946)	$ 140,489	$ 101,328
Net income attributable to noncontrolling interest	(156)	(406)	(91)	(312)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ (6,128)	$ (5,352)	$ 140,398	$ 101,016

Amounts attributable to Series A convertible redeemable preferred units		4,651		3,336		3,995		
General partner s interest, including IDRs		2,800		662		5,252		4,303
Amount allocated to non-vested common units				(79)		965		869
Beneficial conversion feature for Class D common units						820		7,199
Limited partners interest in net (loss) income	$	(13,579)	$	(9,271)	$	129,366	$	88,645
Basic and diluted (loss) income from continuing operations per unit:								
Amount allocated to common units	$	(12,359)	$	(8,966)	$	131,752	$	75,204
Weighted average number of common units outstanding		130,619,554		92,788,319		80,582,705		66,190,626
Basic (loss) income from continuing operations per common and subordinated unit	$	(0.09)	$	(0.10)	$	1.63	$	1.14
Diluted (loss) income from continuing operations per common and subordinated unit	$	(0.09)	$	(0.10)	$	1.63	$	1.10
Distributions paid per unit	$	0.89	$	0.89	$	1.78	$	1.71
Basic and diluted (loss) income on discontinued operations per unit	$	(0.01)	$		$	(0.03)	$	0.21
Basic and diluted net (loss) income per unit:								
Amount allocated to common units	$	(13,579)	$	(9,271)	$	129,366	$	88,645
Basic net (loss) income per common and subordinated unit	$	(0.10)	$	(0.10)	$	1.61	$	1.34
Diluted net (loss) income per common and subordinated unit	$	(0.10)	$	(0.10)	$	1.60	$	1.28
Amount allocated to Class D common units	$		$		$	820	$	7,199
Total number of Class D common units outstanding						7,276,506		7,276,506
Income per Class D common unit due to beneficial conversion feature	$		$		$	0.11	$	0.99
Distributions paid per unit	$		$		$		$	

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Comprehensive (Loss) Income

(in thousands)

	Successor	Predecessor		
	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
Net (loss) income	$ (5,972)	$ (4,946)	$ 140,489	$ 101,328
Net cash flow hedge amounts reclassified to earnings		2,145	(47,394)	35,512
Net change in fair value of cash flow hedges	(11,099)	18,486	(22,040)	70,253
Comprehensive (loss) income	$ (17,071)	$ 15,685	$ 71,055	$ 207,093
Comprehensive income attributable to noncontrolling interest	156	406	91	312
Comprehensive (loss) income attributable to Regency Energy Partners LP	$ (17,227)	$ 15,279	$ 70,964	$ 206,781

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Cash Flows

(in thousands)

	Successor	Predecessor		
	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
OPERATING ACTIVITIES				
Net (loss) income	$ (5,972)	$ (4,946)	$ 140,489	$ 101,328
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:				
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	79,323	49,363	116,307	105,324
Write-off of debt issuance costs and bond premium	(1,422)	1,780		
Amortization of excess fair value of unconsolidated subsidiaries	3,410			
Income from unconsolidated subsidiaries	(56,903)	(15,872)	(7,886)	
Derivative valuation changes	33,189	12,004	5,163	(14,700)
Loss (gain) on asset sales, net	268	303	(133,284)	472
Unit-based compensation expenses	1,827	12,070	6,008	4,306
Gain on insurance settlements				(3,282)
Cash flow changes in current assets and liabilities, net of acquisition effects:				
Trade accounts receivable, accrued revenues, and related party receivables	(401)	(11,272)	10,727	18,648
Other current assets	(107)	2,516	10,471	(6,615)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(15,302)	8,649	(3,762)	(40,772)
Other current liabilities	(12,853)	22,614	(6,726)	12,749
Distributions received from unconsolidated subsidiaries	56,903	12,446	7,886	
Other assets and liabilities	(2,174)	(234)	(1,433)	3,840
Net cash flows provided by operating activities	79,786	89,421	143,960	181,298
INVESTING ACTIVITIES				
Capital expenditures	(159,223)	(63,787)	(193,083)	(375,083)
Capital contributions to unconsolidated subsidiaries	(85,828)	(20,210)		
Distributions in excess of earnings of unconsolidated subsidiaries	59,066		1,039	
Acquisition of investment in unconsolidated subsidiary, net of cash received	4,632	(75,114)		
Acquisitions, net of cash of $1,983, $0, $0 and $1,015	(191,313)		(52,803)	(577,668)
Net proceeds from asset sales	76,237	10,661	88,682	840
Proceeds from insurance settlement				3,282
Net cash flows used in investing activities	(296,429)	(148,450)	(156,165)	(948,629)
FINANCING ACTIVITIES				
Net (repayments) borrowings under revolving credit facility	(333,650)	199,008	(349,087)	644,729
Proceeds from issuance of senior notes	600,000		236,240	
Redemption of senior notes	(357,500)			
Debt issuance costs	(12,389)	(15,728)	(12,224)	(2,940)
Partner contributions	27,999		6,344	11,746
Partner distributions	(118,630)	(86,078)	(146,585)	(120,591)
Acquisition of assets between entities under common control in excess of historical cost		(16,973)	(10,197)	
Contributions from noncontrolling interest	86			
Distributions to noncontrolling interest		(1,135)		
Proceeds from exercises of common unit options	1,937	120		2,700
Proceeds from equity issuances, net of issuance costs	399,582	(89)	220,318	199,315

Proceeds from Series A convertible redeemable preferred units issuance, net of issuance costs						76,624		
Distributions to Series A convertible redeemable preferred units		(3,891)		(1,945)				
Tax withholding on unit-based vesting		(485)		(4,994)				
Net cash flows provided by financing activities		203,059		72,186		21,433		734,959
Net change in cash and cash equivalents		(13,584)		13,157		9,228		(32,372)
Cash and cash equivalents at beginning of period		22,984		9,827		599		32,971
Cash and cash equivalents at end of period	$	9,400	$	22,984	$	9,827	$	599
Supplemental cash flow information:								
Non-cash capital expenditures in liabilities	$	19,635	$	18,051	$	9,688	$	25,845
Issuance of common units for investment in unconsolidated subsidiaries		584,436						219,560
Deemed contribution from acquisition of assets between entities under common control		8,937						
Release of escrow payable from restricted cash		1,011		500		8,501		4,570
Interest paid, net of amounts capitalized		58,335		5,410		69,401		59,969
Income taxes paid		937		378		6		605
Contribution of RIG to HPC						263,921		
Non-cash proceeds from contribution of RIG to HPC						403,568		
Distributions accrued but not paid to Series A convertible redeemable preferred units						3,891		

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Partners Capital and Noncontrolling Interest

(in thousands except unit data)

	Units							
	Common	**Class D, Class E and Subordinated**	**Common Unitholders**	**Class D, Class E and Subordinated Unitholders**	**General Partner Interest**	**Accumulated Other Comprehensive Income (Loss)**	**Noncontrolling Interest**	**Total**
Predecessor								
Balance December 31, 2007	40,514,895	23,804,930	$ 490,351	$ 99,981	$ 11,286	$ (38,325)	$ 4,893	$ 568,186
Issuance of Class D common units		7,276,506		219,560				219,560
Issuance of restricted common units and option exercises, net of forfeitures	559,863		2,700					2,700
Public common units offerings	9,020,909		199,315					199,315
Working capital adjustment on FrontStreet				(858)				(858)
Acquisition on noncontrolling interest							(4,893)	(4,893)
Conversion of Class E common units	4,701,034	(4,701,034)	92,104	(92,104)				
Unit based compensation expenses			4,306					4,306
Partner distributions			(84,207)	(32,668)	(3,716)			(120,591)
Partner contributions					11,746			11,746
Net income			59,592	31,457	9,967		312	101,328
Contributions from noncontrolling interest							12,849	12,849
Net cash flow hedge amounts reclassified to earnings						35,512		35,512
Net change in fair value of cash flow hedges						70,253		70,253
Balance December 31, 2008	54,796,701	26,380,402	764,161	225,368	29,283	67,440	13,161	1,099,413
Revision of partner interest			6,073		(6,073)			
Issuance of restricted common units, net of forfeitures	(63,750)							
Public common units offerings	12,075,000		220,318					220,318
Conversion of subordinated units	19,103,896	(19,103,896)	(1,391)	1,391				
Unit based compensation expenses			6,008					6,008
Accrued distributions to phantom units			(249)					(249)
Acquisition of assets between entities under common control in excess of historical cost					(10,197)			(10,197)
Partner distributions			(141,225)		(5,360)			(146,585)
Partner contributions					6,344			6,344
Net income			134,326	820	5,252		91	140,489
Conversion of Class D common units	7,276,506	(7,276,506)	227,579	(227,579)				
Contributions from noncontrolling interest							898	898
Accrued distributions to Series A convertible redeemable preferred units			(3,891)					(3,891)
Accretion of Series A convertible redeemable preferred units			(104)					(104)
						(47,394)		(47,394)

Net cash flow hedge amounts reclassified to earnings		
Net change in fair value of cash flow hedges	(22,040)	(22,040)

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 thousands except unit data)

	Units							
	Common	Class D, Class E and Subordinated	Common Unitholders	Class D, Class E and Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance December 31, 2009	93,188,353		1,211,605		19,249	(1,994)	14,150	1,243,010
Issuance of common units under LTIP, net of forfeitures and tax withholding	152,075		(4,994)					(4,994)
Issuance of common units, net of costs			(89)					(89)
Proceeds from exercise of common unit options			120					120
Unit-based compensation expenses			12,070					12,070
Accrued distributions to phantom units			(473)					(473)
Acquisition of assets between entities under common control in excess of historical cost					(16,973)			(16,973)
Partner distributions			(82,930)		(3,148)			(86,078)
Distributions to noncontrolling interest							(1,135)	(1,135)
Net (loss) income			(6,014)		662		406	(4,946)
Distributions to Series A convertible redeemable preferred units			(1,906)		(39)			(1,945)
Accretion of Series A convertible redeemable preferred units			(55)					(55)
Net cash flow hedge amounts reclassified to earnings						2,145		2,145
Net change in fair value of cash flow hedges						18,486		18,486
Balance May 25, 2010	93,340,428		$ 1,127,334	$	$ (249)	$ 18,637	$ 13,421	$ 1,159,143
Successor								
Balance May 26, 2010	93,340,428		$ 2,073,532	$	$ 304,950	$	$ 31,450	$ 2,409,932
Private common unit offerings, net of costs	26,266,791		584,436					584,436
Public common unit offerings, net of costs	17,537,500		399,582					399,582
Issuance of common units under LTIP, net of forfeitures and tax withholding	42,417		(485)					(485)
Proceeds from exercise of common unit options	94,200		1,937					1,937
Unit-based compensation expenses			1,827					1,827
Acquisition of assets between entities under common control below historical cost					8,937			8,937
Partner contributions			7,193		20,806			27,999
Partner distributions			(114,292)		(4,338)			(118,630)
Contributions from noncontrolling interest							86	86
Accrued distributions to phantom units			(107)					(107)
Net (loss) income			(8,928)		2,800		156	(5,972)
Distributions to Series A convertible redeemable preferred units			(3,813)		(78)			(3,891)
Accretion of Series A convertible redeemable preferred units			(150)					(150)

Net change in fair value of cash flow hedges					(11,099)		(11,099)
Balance December 31, 2010	137,281,336	$ 2,940,732	$	$ 333,077	$ (11,099)	$ 31,692	$ 3,294,402

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Notes to Consolidated Financial Statements

For the Year Ended December 31, 2010

1. Organization and Basis of Presentation

Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries (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, processing and transporting natural gas and NGLs as well as providing contract compression and contract treating services. 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 January 2008, the Partnership acquired all of the outstanding equity and noncontrolling interest (the FrontStreet Acquisition) of FrontStreet from ASC, an affiliate of GECC, and EnergyOne. Because the acquisition of ASC s 95 percent interest was a transaction between commonly controlled entities, the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Information included in these financial statements is presented as if the FrontStreet Acquisition had been combined throughout the periods presented in which common control existed, June 18, 2007 forward. Conversely, the acquisition of EnergyOne s noncontrolling interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting.

In March 2009, the Partnership contributed RIG to HPC in exchange for a noncontrolling interest in that joint venture. Accordingly, the Partnership no longer consolidates RIG in its financial statements, and accounts for its investment in HPC under the equity method. Transactions between the Partnership and HPC involve the transportation of natural gas, contract compression services, and the provision of administrative support. Because these transactions are immediately realized, the Partnership does not eliminate these transactions with its equity method investee.

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:

	At May 26, 2010 (in thousands)
Fair value of limited partners interest, based on the number of outstanding Partnership common units and the trading price on May 26, 2010	$ 2,073,532
Fair value of consideration paid for general partner interest	304,950
Noncontrolling interest	31,450
	$ 2,409,932

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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.

		($ in thousands)
Working capital	$	(3,286)
Gathering and transmission systems		471,169
Compression equipment		745,838
Gas plants and buildings		116,967
Other property, plant and equipment		100,264
Construction-in-progress		114,146
Other long-term assets		37,694
Investment in unconsolidated subsidiary		739,164
Intangible assets		666,360
Goodwill		789,789
	$	3,778,105
Less:		
Series A convertible redeemable preferred units		70,793
Fair value of long-term debt		1,239,863
Other long-term liabilities		57,517
Total fair value of partners capital	$	2,409,932

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 confirmed 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.

Restricted Cash. Restricted cash held in escrow was for purchase indemnifications related to the El Paso acquisition and for environmental remediation projects. A third-party agent invested funds held in escrow in

United States Treasury securities. Interest earned on the investment was credited to the escrow account. Amounts in the escrow account were released in 2010.

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

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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 periods from May 26, 2010 to December 31, 2010, and from January 1, 2010 to May 25, 2010, as well as for the years ended December 31, 2009, and 2008, the Partnership capitalized interest of $1,425,000, $881,000, $1,722,000 and $2,409,000, 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, and 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 $60,071,000, $37,137,000, $89,706,000 and $81,730,000 for the periods from May 26, 2010 to December 31, 2010, and from January 1, 2010 to May 25, 2010, as well as for the years ended December 31, 2009, and 2008, respectively. Depreciation of 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	5 - 20
Compression Equipment	10 - 30
Gas Plants and Buildings	15 - 35
Other property, plant and equipment	3 - 10

Intangible Assets. As of December 31, 2010, 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. Prior to the ETE Acquisition, the Partnership s intangible assets consisted of (i) permits and licenses, (ii) customer contracts, (iii) trade names, and (iv) customer relations. The intangibles were amortized on a straight line basis over their estimated useful lives which ranged from three 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 2010, 2009 or 2008.

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. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to 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. The Partnership did not record any impairment in 2010, 2009 or 2008.

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. Taxes incurred on behalf of, and passed through to, the Partnership s compression customers are accounted for on a net basis.

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, 2010 and 2009 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 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 at a price approximating the index price and NGLs 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 to create offsetting positions to specific commodity price exposures. Derivative financial instruments are recorded on the balance sheet at their fair value by settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Derivative financial instruments qualifying for hedge accounting treatment have been designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents 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 assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. If the Partnership determines that a derivative is no longer highly effective as a hedge, it discontinues hedge accounting prospectively by including changes in the fair value of the 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 until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge s change in value is

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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. For the Partnership s derivative financial instruments that were not designated for hedge accounting, the change in market value is recorded as a component of net unrealized and realized gain (loss) from derivatives in the consolidated statements of operations.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The Partnership provides a matching contribution for employee contributions to their 401(k) accounts, which vests ratably over 3 years. Effective January 1, 2011, our 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 periods from May 26, 2010 to December 31, 2010, and from January 1, 2010 to May 25, 2010, as well as for the years ended December 31, 2009, and 2008, were $1,963,000, $474,000, $1,263,000 and $727,000, respectively, and were recorded in general and administrative expenses. The Partnership has no pension obligations or other post employment benefits.

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 margin 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 $6,185,000 and $6,996,000 as of December 31, 2010 and 2009, 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 sheet. 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, 2010 and 2009. The Partnership recognized current federal income tax expense (benefit) of $569,000, ($186,000), ($420,000) and $62,000 and deferred income tax expense (benefit) of ($90,000), $307,000, ($1,160,000) and ($486,000) using a 35 percent effective rate for the periods from May 26, 2010 to December 31, 2010, and from January 1, 2010 to May 25, 2010, as well as for the years ended December 31, 2009 and 2008, respectively.

On December 31, 2010, Gulf States Transmission Corporation converted to a limited liability company, resulting in a $239,000 net tax expense.

As of December 31, 2010, the IRS is conducting an audit of the tax returns of Pueblo Holdings Inc., a wholly-owned subsidiary of the Partnership, for the tax years ended December 31, 2007 and December 31, 2008. In addition, the IRS commenced audits of the Partnership s 2007 and 2008 partnership tax returns on January 27, 2010. The Partnership understands this to be a routine audit of various items of partnership income, gain, deductions, losses and credits. The audit is ongoing and the IRS has proposed various adjustments to the Partnership s tax returns, which the Partnership expects to appeal. It is not known whether such adjustments would be material, or how such adjustments would affect unitholders.

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 and the beneficial conversion feature related to the Class D common units are considered deemed distributions. Distributions and deemed distributions to the Series A Preferred Units as well as the beneficial conversion feature of the Class D common units reduce the amount of

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net income available to the general partner and limited partner interests. The general partners interest in net income or loss consists of its two percent 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 computed using the treasury stock method. Common and subordinated units are considered to be a single class for the years ended December 31, 2009 and 2008. 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.

Revision to Partners Capital Accounts. In 2009, the Partnership revised the allocation of net income between the General Partner and common unitholders from the third quarter of 2008 to reflect the income allocation provisions of the Partnership agreement. The effect of this revision was not material to the prior financial statements.

Recently Issued Accounting Standards. In June 2009, the FASB issued guidance that significantly changed the consolidation model for variable interest entities. The guidance became effective for annual reporting periods that began after November 15, 2009, and for interim periods within 2010. The Partnership determined that this guidance had no impact on its financial position, results of operations or cash flows upon adoption on January 1, 2010.

In January 2010, the FASB issued guidance requiring improved disclosure of transfers in and out of Levels 1 and 2 for an entity s fair value measurements, such requirement becoming effective for interim and annual periods beginning after December 15, 2009. Further, additional disclosure of activities such as purchases, sales, issuances and settlements of items relying on Level 3 inputs will be required, such requirements becoming effective for interim and annual periods beginning after December 15, 2010. The Partnership determined that this guidance with respect to Levels 1, 2 and 3 had no impact on its financial position, results of operations or cash flows upon adoption.

In February 2010, the FASB clarified the type of embedded credit derivative that is exempt from embedded derivative bifurcation requirements. The Partnership evaluated the impact of this update on its accounting for embedded derivatives and determined that it had no impact on its financial position, results of operations or cash flows upon adoption.

In December 2010, the FASB issued guidance on when to perform step 2 of the goodwill impairment test for reporting units with zero or negative carrying amounts, which is effective for fiscal years and interim periods within those years beginning after December 15, 2010. The Partnership determined that this guidance had no impact on its financial position, results of operations or cash flows upon adoption.

In December 2010, the FASB issued guidance on disclosure of supplementary pro forma information for business combinations. The guidance specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The guidance also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, non-recurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenues and earnings. These amendments are effective prospectively for business combinations with an acquisition date on or after December 15, 2010, however, early adoption is permitted. The Partnership has elected to early adopt this guidance and has applied this guidance to the pro forma disclosures.

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3. Partners Capital and Distributions

Public Common Unit Offerings. In August 2010, the Partnership sold 17,537,500 common units and received $408,100,000 in proceeds, inclusive of the General Partner s proportionate capital contribution. In December 2009, the Partnership sold 12,075,000 common units and received $225,030,000 in proceeds, inclusive of the General Partner s proportionate capital contribution. In August 2008, the Partnership sold 9,020,909 common units and received $204,133,000 in proceeds, inclusive of the General Partner s proportionate capital contribution.

Private Common Unit Offerings. On May 26, 2010, the Partnership issued 26,266,791 common units, valued at $584,436,000, to ETE, to purchase a 49.9 percent 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 under Section 4(2) thereof. Subsequently, ETE contributed $12,288,000 as the General Partner s proportionate capital.

Subordinated Units. The subordinated units converted into common units on a one-for-one basis on February 17, 2009.

Class E Common Units. On January 7, 2008, the Partnership issued 4,701,034 of Class E common units to ASC as consideration for the FrontStreet Acquisition. The Class E common units had the same terms and conditions as the Partnership s common units, except that the Class E common units were not entitled to participate in earnings or distributions by the Partnership. The Class E common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act under Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Class D Common Units. On January 15, 2008, the Partnership issued 7,276,506 of Class D common units to CDM as partial consideration for the CDM acquisition. The Class D common units had the same terms and conditions as the Partnership s common units, except that the Class D common units were not entitled to participate in earnings or distributions by the Partnership. The Class D common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act under Section 4(2) thereof. The Class D common units converted into common units without the payment of further consideration on a one-for-one basis on February 9, 2009.

Noncontrolling Interest. The Partnership operates a gas gathering joint venture in south Texas in which a third party owns a 40 percent interest, which is reflected on the balance sheet in 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 2 percent of all quarterly distributions that the Partnership makes prior to its liquidation. This General Partner interest is represented by 2,801,660 equivalent units as of December 31, 2010. 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 percent interest in these distributions will be 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 2 percent General Partner interest.

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 2 percent general partner interest.

Distributions of Available Cash. The partnership agreement requires that it make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

first, 98 percent to all unitholders, pro rata, and 2 percent to the General Partner, until each unitholder receives a total of $0.35 per unit outstanding for that quarter;

second, 98 percent to all unitholders, pro rata, and 2 percent to the General Partner, until each unitholder receives a total of $0.4025 per unit outstanding for that quarter;

third, 85 percent to all unitholders, pro rata, 13 percent to holders of the IDRs, and 2 percent to the General Partner, until the aggregate distributions equal $0.4375 per unit outstanding for that quarter;

fourth, 75 percent to all unitholders, pro rata, 23 percent to holders of the IDRs, and 2 percent to the General Partner, until the aggregate distributions equal $0.525 per unit outstanding for that quarter; and

thereafter, 50 percent to all unitholders, pro rata, 48 percent to holders of the IDRs, and 2 percent to the General Partner.

Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2010 and 2009:

Distribution Date	Cash Distribution (per Unit)
November 12, 2010	$ 0.445
August 13, 2010	0.445
May 14, 2010	0.445
February 14, 2010	0.445
November 13, 2009	0.445
August 14, 2009	0.445
May 14, 2009	0.445
February 13, 2009	0.445

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4. (Loss) 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, 2009 and 2008.

	For the Year Ended December 31, 2009			For the Year Ended December 31, 2008		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)					
Basic (loss) income from continuing operations per unit						
Limited partners interests	$ 131,752	80,582,705	$ 1.63	$ 75,204	66,190,626	$ 1.14
Effect of Dilutive Securities						
Restricted (non-vested) common units					5,451	
Common unit options					30,580	
Phantom units		100,764				
Class D common units	820	797,425		7,199	6,978,289	
Class E common units					1,618,389	
Diluted Earnings per Unit	$ 132,572	81,480,894	$ 1.63	$ 82,403	74,823,335	$ 1.10

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 because all instruments were antidilutive.

In connection with the CDM acquisition, the Partnership issued 7,276,506 Class D common units. At the commitment date, the sales price of $30.18 per unit represented a $1.10 discount from the fair value of the Partnership s common units. This discount represented a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class D common units were outstanding, as indicated on the statements of operations in the line item entitled beneficial conversion feature for Class D common units.

In connection with the FrontStreet Acquisition, the Partnership issued 4,701,034 Class E common units to ASC, an affiliate of GECC. Because this transaction represented the acquisition of an entity under common control, the Partnership applied a method of accounting similar to a pooling of interests. The amount of net income allocated to the Class E common units represents amounts earned by FrontStreet between the date of common control and the transaction date. The amount of distributions per unit reflects amounts paid out to the owners of FrontStreet prior to the acquisition.

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		
	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to Disposition (May 25, 2010)	Year ended December 31, 2009	Year ended December 31, 2008
Restricted (non-vested) common units		396,918	566,493	
Phantom units*	366,489	369,346		
Common unit options	259,650	298,400	357,489	
Series A Preferred Units	4,584,192	4,584,192	1,449,211	

* Amount disclosed assumes maximum conversion rate for market condition awards.

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

5. Acquisitions and Dispositions

2010

HPC. On April 30, 2010, the Partnership purchased an additional 6.99 percent general partner interest in HPC from EFS Haynesville, bringing its total general partner interest in HPC to 49.99 percent. The purchase price of $92,087,000 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 $16,973,000, which represented a deemed distribution of the excess purchase price over EFS Haynesville s carrying amount of $75,114,000.

MEP. On May 26, 2010, the Partnership purchased a 49.9 percent interest in MEP from ETE. The Partnership issued 26,266,791 common units to ETE, valued at $584,436,000, and received a working capital adjustment of $4,632,000 from ETE that was recorded as an adjustment to investment in unconsolidated subsidiaries. Because this transaction occurred between two entities under common control, partners capital was increased by $8,937,000, which represented a deemed contribution of the excess carrying amount of ETE s investment of $588,741,000 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 $70,180,000 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 years ended December 31, 2009 and 2008 were $9,510,000, $24,196,000, $46,220,000, and $78,541,000, respectively.

Zephyr. On September 1, 2010, the Partnership completed the Zephyr acquisition for $193,296,000 in cash that was funded by borrowing 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 $13,662,000 and $5,900,000, respectively are included in the Partnership s results of operations. The total purchase price was allocated as follows.

	At September 1, 2010 (in thousands)	
Cash and cash equivalents	$	1,983
Trade accounts receivable		6,580
Other current assets		128
Gas plants and buildings		80,859
Other property, plant and equipment		303
Intangible assets		119,379
Total assets acquired	$	209,232
Trade accounts payable		(8,364)
Deferred revenues		(6,408)
Other current liabilities		(1,164)
Net assets acquired	$	193,296

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2009

HPC. In March 2009, the Partnership completed a joint venture arrangement among Regency HIG, EFS Haynesville, and the Alinda Investors. The Partnership contributed RIG, which owns the RIGS, with a fair value of $401,356,000, to HPC, in exchange for a 38 percent general partner interest in HPC. EFS Haynesville and Alinda Investors contributed $126,928,000 and $528,284,000 in cash, respectively, to HPC in return for a 12 percent general partner and a 50 percent general partner interest, respectively. The disposition and deconsolidation resulted in the recording of a $133,451,000 gain (of which $52,813,000 represents the remeasurement of the Partnership s retained 38 percent general partner interest to its fair value), net of transaction costs of $5,530,000.

In September 2009, the Partnership purchased a five percent general partner interest in HPC from EFS Haynesville for $63,000,000, increasing the Partnership s general partner ownership percentage from 38 percent to 43 percent. Because the transaction occurred between two entities under common control, the Partnership s general partner interest was reduced by $10,197,000, which represented a deemed distribution of the excess purchase price over EFS Haynesville s carrying amount.

2008

FrontStreet. In January 2008, the Partnership completed the FrontStreet Acquisition. FrontStreet owned a gas gathering system located in Kansas and Oklahoma, which is operated by a third party. The total purchase price consisted of (a) 4,701,034 Class E common units of the Partnership issued to ASC in exchange for its 95 percent interest and (b) $11,752,000 in cash to EnergyOne in exchange for its five percent minority interest and the termination of a management services contract valued at $3,888,000. The Partnership financed the cash portion of the purchase price with borrowings under its revolving credit facility.

Because the acquisition of ASC s 95 percent interest was a transaction between commonly controlled entities, the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Information included in these financial statements is presented as if the FrontStreet Acquisition had been combined throughout the periods presented in which common control existed, June 18, 2007 forward. Conversely, the acquisition of the five percent minority interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting.

The following table summarizes the book value of the assets acquired and the liabilities assumed at the date of common control, following the as if pooled method of accounting.

	At June 18, 2007 (in thousands)
Current assets	$ 8,840
Property, plant and equipment	91,556
Total assets acquired	100,396
Current liabilities	(12,556)
Net book value of assets acquired	$ 87,840

CDM Resource Management, Ltd. In January 2008, the Partnership acquired CDM by (a) issuing an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000 and (b) paying an aggregate of $478,445,000 in cash, $316,500,000 of which was used to retire CDM s debt obligations.

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The total purchase price of $699,841,000, including direct transaction costs, was allocated as follows.

	At January 15, 2008 (in thousands)
Current assets	$ 19,463
Other assets	4,658
Gas plants and buildings	1,528
Gathering and transmission systems	420,974
Other property, plant and equipment	2,728
Construction-in-process	36,239
Identifiable intangible assets	80,480
Goodwill	164,882
Assets acquired	730,952
Current liabilities	(31,054)
Other liabilities	(57)
Net assets acquired	$ 699,841

Nexus Gas Holdings, LLC. In March 2008, the Partnership acquired Nexus (Nexus Acquisition) for $88,486,000 in cash. The Partnership funded the Nexus Acquisition through borrowings under its existing credit facility.

The total purchase price of $88,640,000 was allocated as follows.

	At March 25, 2008 (in thousands)
Current assets	$ 3,457
Buildings	13
Gathering and transmission systems	16,960
Other property, plant and equipment	4,440
Identifiable intangible assets	61,100
Goodwill	3,341
Assets acquired	89,311
Current liabilities	(671)
Net assets acquired	$ 88,640

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The following unaudited pro forma financial information has been prepared as if the transactions involving the contribution of RIG to HPC, the purchases of the 5 percent and 6.99 percent general partner interest in HPC, the purchase of the 49.9 percent interest in MEP, the application of Push-down Adjustments as described in Note 1, and the acquisition of Zephyr occurred as of January 1, 2009. Such pro forma financial does not purport to be indicative of the results of the operations that would have been achieved if the transaction to which the Partnership is giving pro forma effect actually occurred on January 1, 2009 or the results of operations that may be expected in the future.

	Successor	Predecessor	
	Period from May 26, 2010 to December 31, 2010 (in thousands except unit and per unit data)	Period from January 1, 2010 to May 25, 2010 (in thousands except unit and per unit data)	Year Ended December 31, 2009
Revenue	$ 732,309	$ 531,135	$ 1,052,092
Net (loss) income attributable to Regency Energy Partners LP	(5,146)	(1,407)*	96,190*
Less:			
Amounts attributable to Series A Preferred Units	4,651	3,336	3,995
General partner s interest, including IDRs	2,820	(446)	4,368
Amount allocated to non-vested common units		(298)	376
Beneficial conversion feature for Class D common units			820
Limited partners interest in pro forma net (loss) income	$ (12,617)	$ (3,999)	$ 86,631
Basic and diluted pro forma net (loss) income per unit:			
Amount allocated to common units	$ (12,617)	$ (3,999)	$ 86,631
Weighted average number of common units outstanding	130,619,554	92,788,319	80,582,705
Basic and diluted pro forma net (loss) income per common unit	$ (0.10)	$ (0.04)	$ 1.08
Distributions paid per unit	$ 0.89	$ 0.89	$ 1.78
Amount allocated to Class D common units	$	$	$ 820
Total number of Class D common units outstanding			7,276,506
Income per Class D common unit due to beneficial conversion feature	$	$	$ 0.11
Distributions paid per unit	$	$	$

* As a result of the change in control of the General Partner in May 2010, a one-time charge of $9,893,000 related to the vesting of the Partnership s then outstanding restricted (non-vested) units and outstanding phantom units under its LTIP was recorded in the same month. In calculating the pro forma net (loss) income attributable to Regency Energy Partners LP, this charge was reversed in the period from January 1, 2010 through May 25, 2010, and was recorded in the year ended December 31, 2009.

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6. Investment in Unconsolidated Subsidiaries

Investment in HPC. HPC was established in March 2009 and as of December 31, 2010, the Partnership owned a 49.99 percent general partner interest in HPC. The following table summarizes the changes in the Partnership s investment in HPC.

	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to December 31, 2010	Period from January 1, 2010 to Disposition (May 25, 2010)	Period from Inception (March 18, 2009) to December 31, 2009
	(in thousands)	(in thousands)	
Contributions to HPC	$	$ 20,210	$ 401,356
Purchase of additional HPC general partner interests		75,114	52,803
Distributions received from HPC	52,668	12,446	8,926
Return of investment received from HPC	19,995		
Partnership s share of HPC s net income	35,684	15,872	7,886

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) $154,926,000 was attributed to HPC s long-lived assets and is being amortized as a reduction of income from unconsolidated subsidiaries over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32,368,000 could not be attributed to a specific asset and therefore will not be amortized in future periods. For the period from May 26, 2010 to December 31, 2010, the Partnership recorded $3,410,000, as a reduction of income from unconsolidated subsidiaries due to the amortization of the excess fair value of long-lived assets.

The HPC partnership agreement requires the distribution of 100 percent of available cash to the partners in accordance with their sharing ratios within 30 days after the end of each calendar quarter. Available cash is defined as cash on hand (excluding cash restricted for HPC s expansion project), less amounts reserved for normal operating expenses.

Investment in MEP. On May 26, 2010, the Partnership purchased a 49.9 percent interest in MEP from ETE. The Partnership made capital contributions of $85,828,000 to MEP during 2010. During the period from May 26, 2010 to December 31, 2010, the Partnership recognized $21,219,000 in income from unconsolidated subsidiaries for its ownership interest and received $43,306,000 in distributions from MEP.

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 Risk Management Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Risk Management 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.

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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 executed swap contracts settled against NGLs (ethane, propane, butane, and natural gasoline), condensate and natural gas market prices for expected equity exposure in the approximate percentages set for forth.

	As of December 31, 2010		As of January 31, 2011	
	2011	**2012**	**2011**	**2012**
NGLs	88%	31%	88%	47%
Condensate	84%	37%	84%	55%
Natural gas	76%	25%	76%	25%

At December 31, 2010, all of the Partnership s commodity swaps are accounted for as cash flow hedges.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its credit facility. As of December 31, 2010, the Partnership had $285,000,000 of outstanding borrowings exposed to variable interest rate risk. The Partnership s $300,000,000 interest rate swaps expired in March 2010. In April 2010, the Partnership entered into two-year interest rate swaps related to $250,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 1.325 percent through April 2012. The Partnership accounts for interest rate swaps on a mark-to-market basis.

Credit Risk. The Partnership s resale of 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 credit-worthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or a 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. The Partnership has entered into Master ISDA 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, 2010 was $2,673,000, which would be reduced in full due to the netting feature. The Partnership has elected to present assets and liabilities under Master ISDA Agreements gross on the 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.

Quantitative Disclosures. The Partnership expects to reclassify $8,354,000 of net hedging losses to revenues from accumulated other comprehensive loss in the next 12 months.

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The Partnership s derivative assets and liabilities, including credit risk adjustment, for the years ended December 31, 2010 and 2009 are detailed below.

	Assets		Liabilities	
	December 31, 2010	December 31, 2009	December 31, 2010	December 31, 2009
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$	$	$	$ 1,064
Commodity contracts	2,650	9,521	11,421	11,161
Long-term amounts				
Commodity contracts	23	207	3,271	931
Total cash flow hedging instruments	2,673	9,728	14,692	13,156
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts		15,466		31
Interest rate contracts			1,751	
Long-term amounts				
Commodity contracts				3,378
Interest rate contracts			833	
Embedded derivatives in Series A Preferred Units			57,023	44,594
Total derivatives not designated as cash flow hedges		15,466	59,607	48,003
Total derivatives	$ 2,673	$ 25,194	$ 74,299	$ 61,159

	Successor	Predecessor		
	Period from May 26, 2010 to December 31, 2010 (in thousands)	Period from January 1, 2010 to May 25, 2010	Year Ended December 31, 2009 (in thousands)	Year Ended December 31, 2008
	Change in Value Gain (Loss) Recognized in AOCI (Effective Portion)			
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$ (11,099)	$ 14,371	$ (19,958)	$ 74,808
Interest rate swap derivatives			(2,082)	(4,555)
	$ (11,099)	$ 14,371	$ (22,040)	$ 70,253

	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	$	$ (5,200)	$ 54,260	$ (35,942)
Interest rate swap derivatives	Interest expense		(1,060)	(6,255)	676

$		$	(6,260)	$	48,005	$	(35,266)

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	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	$ (88)	$ (799)	$ 108	$ 543

	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) from Dedesignation Amortized from AOCI into Income			
Derivatives not designated in a hedging relationship:					
Commodity derivatives	Revenue	$	$ 4,115	$ (611)	$ (246)

	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized into Income			
Derivatives not designated in a hedging relationship:					
Commodity derivatives	Revenue	$ (7,778)	$ 1,168	$ (13,669)	$ 15,911
Interest rate swap derivatives	Interest expense	(3,588)	(824)		
Embedded derivative	Other income & deductions	(8,390)	(4,039)	(15,686)	
		$ (19,756)	$ (3,695)	$ (29,355)	$ 15,911

8. Long-term Debt

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

	December 31, 2010	December 31, 2009
	(in thousands)	
Senior notes	$ 856,061	$ 594,657
Revolving loans	285,000	419,642
Total	1,141,061	1,014,299
Less: current portion		
Long-term debt	$ 1,141,061	$ 1,014,299
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded commitments		(10,675)
Revolving loans	(285,000)	(419,642)
Letters of credit	(16,015)	(16,257)
Total available	$ 598,985	$ 453,426

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Long-term debt maturities as of December 31, 2010 for each of the next five years are as follows.

Year Ended December 31,	Amount (in thousands)
2011	$
2012	
2013	
2014	285,000
2015	
Thereafter	850,000*
Total	$ 1,135,000

* Excludes an unamortized premium of $6,061,000 as of December 31, 2010.

In the year ended December 31, 2010, the Partnership borrowed $603,000,000 under its revolving credit facility; these borrowings were primarily to fund capital expenditures and acquisitions. During the same period, the Partnership repaid $737,642,000 with proceeds from an equity offering and an issuance of senior notes due 2018. In the years ended December 31, 2009 and 2008, the Partnership borrowed $191,693,000 and $844,729,000, respectively; these funds were used primarily to finance capital expenditures and acquisitions. During the same periods, the Partnership repaid $540,780,000, and $200,000,000, respectively, of these borrowings with proceeds from equity offerings.

Revolving Credit Facility. In March 2010, RGS entered into the Fifth Amended and Restated Credit Agreement that extended the maturity date of this facility to June 15, 2014 from August 15, 2011. In May 2010, the Fifth Amended and Restated Credit Agreement amended certain definitions to include MEP, to allow for the pledge of the equity interest in MEP as indirect collateral, to permit certain investments in MEP by the Partnership and its affiliates and to require that the Partnership and its subsidiaries maintain a senior consolidated secured leverage ratio not to exceed three to one.

The Partnership has a $900,000,000 revolving credit facility and the availability for letters of credit is $100,000,000. RGS also has the option to request an additional $250,000,000 in revolving commitments with ten business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the revolving credit facility have been met. RGS is allowed additional investment in HPC up to $250,000,000 as well as other joint venture investments (other than HPC) of up to $75,000,000.

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 of revolving loans 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 percent and an adjusted one-month LIBOR rate plus 1.00 percent. The applicable margin shall range from 1.50 percent to 2.25 percent for base rate loans, 2.50 percent to 3.25 percent for Eurodollar loans, and a commitment fee will range from 0.375 to 0.50 percent.

RGS must pay (i) a commitment fee equal to 0.375 percent per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit equal to 2.5 percent 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 percent 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.

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The outstanding balance of revolving debt under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S prime rate lending rate) plus a margin or a combination of both. The average interest rates for the revolving loans, including commitment fees, were 4.06 percent, 3.60 percent, 3.39 percent and 4.51 percent during the periods from May 26, 2010 to December 31, 2010 and from January 1, 2010 to May 25, 2010, and for the years December 31, 2009 and 2008, respectively.

The Partnership treated the March 2010 amendment of the revolving credit facility as a modification of an existing revolving credit agreement and, therefore, wrote off debt issuance costs of $1,780,000 to interest expense, net in the period from January 1, 2010 to May 25, 2010. In addition, the Partnership paid and capitalized $15,883,000 of loan fees which will be amortized over the remaining term.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.25. At December 31, 2010 and 2009, 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 2013. During the fourth quarter of 2010, in connection with the issuance of $600,000,000 of senior notes due 2018 as further described below, the Partnership redeemed all of its $357,500,000 senior notes due 2013. Accordingly, a redemption premium of $17,170,000 was charged to loss on debt refinancing, net in the consolidated statement of operations. In addition, the Partnership wrote off the unamortized loan fee of $4,970,000 and unamortized bond premium of $6,392,000 to loss on debt refinancing, net in the consolidated statement of operations.

Senior Notes due 2018. In October, 2010, the Partnership and Finance Corp. issued $600,000,000 of senior notes that mature on December 1, 2018. The senior notes bear interest at 6 7/8 percent paid semi-annually in arrears on June 1 and December 1, commencing June 1, 2011. The Partnership capitalized $12,196,000 in debt issuance costs that will be amortized to interest expense, 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 percent of the senior notes can be redeemed at a price of 106.875 percent plus accrued interest. Beginning December 1, 2014, the Partnership may redeem all or part of

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these notes for the principal amount plus a declining premium prior to December 31, 2016, and thereafter at par, plus accrued and unpaid interest. At any time prior to December 1, 2014, the Partnership may also redeem all or part of the notes at a price equal to 100 percent of the principal amount redeemed plus accrued interest and the applicable premium, which equals the greater of (1) one percent 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.

Upon a change of control (as defined) followed by a rating decline within 90 days, each holder of senior notes due 2018 will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent 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 the Partnership s revolving credit facility.

The senior 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 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, 2010, the Partnership was in compliance with these covenants.

Senior Notes due 2016. In May 2009, the Partnership and Finance Corp. issued $250,000,000 of senior notes in a private placement that mature on June 1, 2016. The senior notes bear interest at 9 $^3/8$ percent with interest payable semi-annually in arrears on June 1 and December 1. The Partnership received net proceeds of $236,240,000 upon issuance. The net proceeds were used to partially repay revolving loans under the Partnership s revolving credit facility.

At any time before June 1, 2012, up to 35 percent of the senior notes can be redeemed at a price of 109.375 percent plus accrued interest. Beginning June 1, 2013, the Partnership may redeem all or part of these notes for the principal amount plus a declining premium prior to June 1, 2015, and thereafter at par, plus accrued and unpaid interest. At any time prior to June 1, 2013, the Partnership may also redeem all or part of the notes at a price equal to 100 percent of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) one percent 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.

Upon a change of control (as defined), each noteholder will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent 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, no noteholder exercised this option.

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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, 2010, the Partnership was in compliance with these covenants.

Both the senior notes due 2018 and the senior notes due 2016 are jointly and severally guaranteed by all of the Partnership s current consolidated subsidiaries, other than Finance Corp. and a minor subsidiary, 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. Other Assets

Intangible assets, net. Intangible assets, net consist of the following.

	Contracts	Customer Relations	Trade Names (in thousands)	Permits and Licenses	Total
Predecessor					
Balance at January 1, 2009	$ 126,799	$ 37,417	$ 32,848	$ 8,582	$ 205,646
Disposals				(2,921)	(2,921)
Other	7,000				7,000
Amortization	(7,467)	(2,055)	(2,340)	(569)	(12,431)
Balance at December 31, 2009	126,332	35,362	30,508	5,092	197,294
Amortization	(3,322)	(817)	(975)	(214)	(5,328)

Balance at May 25, 2010	$ 123,010	$ 34,545	$ 29,533	$ 4,878	$ 191,966

	Customer Relations	Trade Names (in thousands)	Total
Successor			
Balance at May 26, 2010	$ 600,860	$ 65,500	$ 666,360
Additions	119,379		119,379
Amortization	(13,673)	(1,911)	(15,584)
Balance at December 31, 2010	$ 706,566	$ 63,589	$ 770,155

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The average remaining amortization periods for customer relations and trade names are 27 and 19 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $29,793,000.

Goodwill. Goodwill activity consists of the following.

	Gathering and Processing	Transportation	Contract Compression	Total
		(in thousands)		
Predecessor				
Balance at January 1, 2009	$ 63,232	$ 34,244	$ 164,882	$ 262,358
Disposals		(34,244)		(34,244)
Balances at December 31, 2009 and May 25, 2010	$ 63,232	$	$ 164,882	$ 228,114
Successor				
Balances at May 26, 2010 and December 31, 2010	$ 313,361	$	$ 476,428	$ 789,789

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 interest rate and commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate and commodity swaps 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 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 change in fair value of the derivatives related to Series A Preferred Units is recorded in other income and deductions, net within the statement of operations.

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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, 2010				Fair Value Measurement at December 31, 2009			
	Fair Value Total	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value Total	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
	(in thousands)							
Assets								
Commodity Derivatives:								
Natural Gas	$ 2,481	$	$ 2,481	$	$ 602	$	$ 602	$
Natural Gas Liquids	192		192		15,484		15,484	
Condensate					9,108		9,108	
Total Assets	$ 2,673	$	$ 2,673	$	$ 25,194	$	$ 25,194	$
Liabilities								
Interest Rate Derivatives	$ 2,584	$	$ 2,584	$	$ 1,064	$	$ 1,064	$
Commodity Derivatives:								
Natural Gas	427		427		51		51	
Natural Gas Liquids	10,684		10,684		15,034		15,034	
Condensate	3,581		3,581		416		416	
Embedded Derivatives in Series A Preferred Units	57,023			57,023	44,594			44,594
Total Liabilities	$ 74,299	$	$ 17,276	$ 57,023	$ 61,159	$	$ 16,565	$ 44,594

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2010 and 2009. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2010 and 2009.

	Embedded Derivatives in Series A Preferred Units (in thousands)
Balance at December 31, 2008	$
Issuance	28,908
Net unrealized loss included in other income and decuctions, net	15,686
Balance at December 31, 2009	44,594
Net unrealized loss included in other income and deductions, net	4,039
Balance at May 25, 2010	48,633
Net unrealized loss included in other income and deductions, net	8,390
Balance at December 31, 2010	$ 57,023

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximates fair value due to the relatively short-term settlement period of the escrow payable. 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 estimated fair value of the senior notes due 2016 based on third party market value quotations as of December 31, 2010 and 2009 was $274,375,000 and $265,625,000, respectively. The estimated fair value of the senior notes due 2018 based on third party market value quotations as of December 31, 2010 was $607,500,000.

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11. Leases

The Partnership leases office space and certain equipment and the following table is a schedule of future minimum lease payments for leases that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2010.

For the year ending December 31,	Operating (in thousands)
2011	$ 4,172
2012	3,566
2013	2,730
2014	2,370
2015	2,296
Thereafter	7,715
Total minimum lease payments	$ 22,849

The Partnership s capital lease obligation was terminated upon the disposition of its gathering and processing assets located in east Texas in July 2010.

Included within the schedule of future minimum lease payments is a Master Lease Agreement between CDM and Caterpillar Financial Services Corporation, with an annual rent expense of $1,224,000. CDM exercised an early buyout option on January 14, 2011, to purchase the leased compression equipment for $9,000,000 and terminated the agreement.

Total rent expense for operating leases, including those leases with terms of less than one year, was $2,723,000, $2,393,000, $5,465,000, and $2,576,000, during the periods from May 26, 2010 to December 31, 2010, from January 1, 2010 to May 25, 2010 and for the years ended December 31, 2009, and 2008, 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 have appealed the verdict. The hearing on appeal will take place sometime in 2011.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. RFS currently owns the Dubach and Calhoun gas processing plants in north Louisiana (the Plants). The Plants each have groundwater contamination as result of historical operations. At the time that RFS acquired the Plants from El Paso Field Services LP (El Paso), Kerr-McGee Corporation (Kerr-McGee) was performing remediation of the groundwater contamination, because the Plants were once owned by Kerr-McGee and when Kerr-McGee sold the Plants to a predecessor of El Paso in 1988, Kerr-McGee retained liability for any environmental contamination at the Plants. In 2005, Kerr-McGee created and spun off Tronox and Tronox allegedly assumed certain of Kerr-McGee s environmental remediation obligations (including its obligation to perform remediation at the Plants) prior to the acquisition of Kerr-McGee by Anadarko Petroleum Corporation. In January 2009, Tronox filed for Chapter 11 bankruptcy protection. RFS filed a claim in the bankruptcy proceeding relating to the environmental remediation work at the Plants. Tronox has thus far continued its remediation efforts at the Plants. Tronox filed a reorganization plan on July 7, 2010. The plan calls for the creation of a trust to fund environmental clean-up at the various sites where Tronox has an obligation. The Partnership anticipates that the amount of the trust allocated for clean-up of the Dubach and Calhoun plants will cover the remaining costs if the method and pace of clean-up remains consistent with historical practice. The Partnership will not report further on this matter absent further adverse developments.

MEP Guarantee. Upon its acquisition of the 49.9 percent interest in MEP from ETE, the Partnership agreed to indemnify ETP for any costs related to ETP s guarantee of payments under MEP s senior revolving credit facility (the MEP Facility). ETP will continue to guarantee 50 percent of the obligations of the MEP Facility, with the remaining 50 percent of MEP Facility obligations guaranteed by KMP. The $175,400,000 MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both ETP s credit rating and that of KMP, with a maximum fee of 0.15 percent. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of December 31, 2010, MEP had no outstanding borrowings and $33,300,000 of letters of credit issued under the MEP Facility. The Partnership s contingent obligations with respect to MEP s letters of credit under the MEP Facility was $16,600,000 as of December 31, 2010.

13. Series A Convertible Redeemable 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 a four percent discount of $3,200,000 and issuance costs of $176,000 for net proceeds of $76,624,000, exclusive of the General Partner s contribution of $1,633,000. 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 $80,000,000 plus all accrued but unpaid distributions thereon (the Series A Liquidation Value). 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. As of December 31, 2010 and 2009, total accrued distributions per unit was $0.89. 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 1,600,000 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

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units (the Covenant Default Additional Amount). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432 percent 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 percent 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) and until December 31, 2011, based on a weighted average formula in the event the Partnership issues any common units (or securities convertible or exercisable into common units) at a per common unit price below $16.47 per common unit (subject to typical exceptions). 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 percent, 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 percent of the then-applicable conversion price for twenty (20) out of the trailing thirty (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 percent 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 percent 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.

Accrued distributions of $3,891,000 were added to the value of the Series A Preferred Units and increases the number of common units to 4,584,192 that may be issued upon conversion. Holders may elect to convert Series A Preferred Units to common units beginning on March 2, 2010.

Net proceeds from the issuance of Series A Preferred Units on September 2, 2009 was $76,624,000, of which $28,908,000 was allocated to the initial fair value of the embedded derivatives and recorded into long-term derivative liabilities on the balance sheet. The remaining $47,716,000 represented the initial value of the Series A Preferred Units and will be accreted to $80,000,000 by deducting the accretion amounts from partners capital over 20 years. As disclosed in Note 1, the Series A Preferred Units were adjusted to fair value of $70,793,000 on May 26, 2010.

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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.

	Units	Amount (in thousands)
Balance at January 1, 2009		$
Original issuance, net of discount	4,371,586	76,624
Amount reclassed to long-term derivative liabilities		(28,908)
Accrued distributions		3,891
Accretion to redemption value		104
Balance at December 31, 2009	4,371,586	51,711
Accretion to redemption value		55
Balance at May 25, 2010	4,371,586	51,766
Fair value adjustment		19,027
Balance at May 26, 2010	4,371,586	70,793
Accretion to redemption value		150
Balance at December 31, 2010	4,371,586	$ 70,943*

* The amount will be accreted to $80,000,000 plus any accrued and unpaid distributions by deducting amounts from partners capital over the 18.75 remaining years.

14. Related Party Transactions

Transactions with ETE. During the period from May 26, 2010 to December 31, 2010, the Partnership received cash of $7,193,000 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). In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $27,716,000 for the period from May 26, 2010 to December 31, 2010.

ETE made capital contributions aggregating to $20,806,000, to maintain the General Partner s two percent interest in the Partnership for the period from May 26, 2010 to December 31, 2010.

On May 26, 2010, the Partnership entered into a services agreement with ETE and ETE Services Company, LLC (Services Co.), a subsidiary of ETE. Under the services agreement, Services Co. will perform certain general and administrative services to the Partnership. The Partnership will pay Services Co. s direct expenses for these services, plus an annual fee of $10,000,000, and will receive the benefit of any cost savings recognized for these services. The services agreement has a five year term, 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. The Partnership incurred service fees of $5,833,000 during the period from May 26, 2010 to December 31, 2010.

The Partnership s Contract Compression segment provides contract compression services to ETE and records revenue in gathering, transportation and other fees on the statement of operations.

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. During the periods from May 26, 2010 to December 31, 2010, from January 1, 2010 to May 25, 2010 and the year ended December 31, 2009, the related party general and administrative expenses reimbursed to the Partnership were $9,800,000, $6,933,000 and $4,726,000, respectively, which is recorded in gathering, transportation and other fees on the statement of operations.

Upon the formation of HPC in March 2009, the Partnership was reimbursed by HPC for construction-in-progress incurred prior to formation of HPC at the cost of $80,608,000. The Partnership sold

property, plant, and equipment of $37,000, $392,000 and $7,984,000 to HPC during the periods from May 26, 2010 to December 31, 2010, from January 1, 2010 to May 25, 2010 and the year ended December 31, 2009, respectively.

The Partnership s Contract Compression segment provides contract 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 Enterprise. Enterprise Products Partners L.P., (EPD), owns approximately 18 percent of ETE s outstanding common units, therefore is 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 with subsidiaries of EPD and records the cost to cost of sales.

Transactions with GE. As part of the August 1, 2008 common units offering, an affiliate of GECC purchased 2,272,727 common units for total consideration of $50,000,000.

Others. The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $44,219,000, $31,065,000, $33,834,000, and $26,899,000, were recorded in the Partnership s financial statements during the periods from May 26, 2010 to December 31, 2010, from January 1, 2010 to May 25, 2010, and the years ended December 31, 2009 and 2008, respectively, as operation and maintenance expenses or general and administrative expenses, as appropriate.

In September 2008, HM Capital and affiliates sold 7,100,000 common units for total consideration of $149,100,000, reducing their ownership percentage to an amount less than ten percent of the Partnership s outstanding common units. As a result of this sale, HM Capital is no longer a related party of the Partnership. During the year ended December 31, 2008, HM Capital and affiliates received cash disbursements, in conjunction with distributions by the Partnership for limited and general partner interests, of $10,308,000.

The Partnership s contract compression segment provided contract compression services to CDM MAX LLC (CDM MAX). In 2009, CDM MAX was purchased by a third party and, as a result, CDM MAX is no longer a related party. The Partnership s related party revenue associated with CDM MAX was $1,101,000 and $3,712,000 during the years ended December 31, 2009 and 2008, respectively.

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As of December 31, 2010 and December 31, 2009, details of the Partnership s related party receivables and related party payables were as follow.

	Successor December 31, 2010 (in thousands)	Predecessor December 31, 2009 (in thousands)
Related party receivables		
EPD	$ 25,539	*
HPC	5,823	$ 6,222
ETE	970	*
Other	10	
Total related party receivables	$ 32,342	$ 6,222
Related party payables		
EPD	$ 1,323	*
HPC	760	$ 2,312
ETE	1,245	*
Other	10	
Total related party payables	$ 3,338	$ 2,312

* EPD and ETE were not related parties to the Partnership as of December 31, 2009.

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 ten percent or more of revenue or cost of gas and liquids are disclosed below, together with the identity of the reporting segment.

	Reportable Segment	Successor Period from May 26, 2010 to December 31, 2010 (in thousands)	Predecessor Period from January 1, 2010 to May 25, 2010	Predecessor Year Ended December 31, 2009 (in thousands)	Predecessor Year Ended December 31, 2008
Customer					
Customer A	Gathering and Processing	$ 131,724	$ 88,003	$ 123,524	*
Customer B	Gathering and Processing	*	$ 52,372	*	*
Supplier					
Supplier A	Transportation	$	$	$ 14,053	$ 75,464
Supplier A	Gathering and Processing	*	*	143,435	243,075

* Amounts are less than ten percent 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.

16. Segment Information

During 2010, the Partnership s management realigned the composition of its segments as described below. The disposition of the east Texas assets impacts the Gathering and Processing segment, as the results of those operations are now presented within discontinued operations and excluded from the segment information table. Accordingly, the Partnership has recast the segment information.

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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.

Transportation. The Partnership owns a 49.99 percent general partner interest in HPC, which delivers natural gas from northwest Louisiana to downstream pipelines and markets through the 450-mile Regency Intrastate Gas pipeline system. The Partnership also owns a 49.9 percent interest in MEP, which owns approximately 500 miles of natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi into Alabama.

Contract Compression. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems.

Contract Treating. The Partnership 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, to natural gas producers and midstream pipeline companies.

Corporate and Others. The Corporate and Others segment comprises a small regulated pipeline and 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 for the Transportation segments, is defined as total revenues, including service fees, less cost of sales. In the Contract Compression segment, segment margin is defined as revenues minus direct costs, which primarily consist of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenue generating horsepower. 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.

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Results for each period, together with amounts related to balance sheets for each segment are shown below.

	Gathering and Processing	Transportation	Contract Compression	Contract Treating	Corporate and Others	Eliminations	Total
				(in thousands)			
External Revenue							
Period from May 26, 2010 to December 31, 2010	$ 606,944	$	$ 86,099	$ 13,662	$ 9,908	$	$ 716,613
Period from January 1, 2010 to May 25, 2010	438,804		58,971		7,275		505,050
Year ended December 31, 2009	879,439	9,078	148,846		5,914		1,043,277
Year ended December 31, 2008	1,609,838	42,400	132,549		476		1,785,263
Intersegment Revenue							
Period from May 26, 2010 to December 31, 2010			14,079		185	(14,264)	
Period from January 1, 2010 to May 25, 2010			9,126		91	(9,217)	
Year ended December 31, 2009	(8,755)	4,933	4,604		296	(1,078)	
Year ended December 31, 2008	42,310	11,422	4,573		339	(58,644)	
Cost of Sales							
Period from May 26, 2010 to December 31, 2010	496,933		8,325	2,208	(2,954)	(185)	504,327
Period from January 1, 2010 to May 25, 2010	352,807		5,741		(679)	(91)	357,778
Year ended December 31, 2009	656,764	2,297	12,422		(65)	3,526	674,944
Year ended December 31, 2008	1,420,642	(13,066)	11,619			(54,071)	1,365,124
Segment Margin							
Period from May 26, 2010 to December 31, 2010	110,011		91,853	11,454	13,047	(14,079)	212,286
Period from January 1, 2010 to May 25, 2010	85,997		62,356		8,045	(9,126)	147,272
Year ended December 31, 2009	213,920	11,714	141,028		6,275	(4,604)	368,333
Year ended December 31, 2008	231,506	66,888	125,503		815	(4,573)	420,139
Operation and Maintenance							
Period from May 26, 2010 to December 31, 2010	53,421		37,067	1,227	172	(14,079)	77,808
Period from January 1, 2010 to May 25, 2010	33,430		23,476		59	(9,123)	47,842
Year ended December 31, 2009	74,962	2,112	45,744		238	(5,976)	117,080
Year ended December 31, 2008	70,775	3,540	49,799		74	(4,473)	119,715
Depreciation and Amortization							
Period from May 26, 2010 to December 31, 2010	45,547		25,771	3,684	965		75,967
Period from January 1, 2010 to May 25, 2010	25,422		15,560		802		41,784
Year ended December 31, 2009	59,654	2,448	36,548		1,448		100,098
Year ended December 31, 2008	49,727	14,099	28,448		1,119		93,393
Income from Unconsolidated Subsidiary							
Period from May 26, 2010 to December 31, 2010		53,493					53,493
Period from January 1, 2010 to May 25, 2010		15,872					15,872
Year ended December 31, 2009		7,886					7,886
Year ended December 31, 2008							
Assets							
December 31, 2010	1,724,682	1,351,256	1,411,325	220,584	62,357		4,770,204
December 31, 2009	1,082,592	453,120	926,213		71,489		2,533,414
Investment in Unconsolidated Subsidiaries							
December 31, 2010		1,351,256					1,351,256
December 31, 2009		453,120					453,120
Goodwill							
December 31, 2010	313,361		476,428				789,789
December 31, 2009	63,232		164,882				228,114
Expenditures for Long-Lived Assets							
Period from May 26, 2010 to December 31, 2010	93,398		44,316	18,106	3,403		159,223
Period from January 1, 2010 to May 25, 2010	43,666		18,418		1,703		63,787
Year ended December 31, 2009	84,097	22,367	83,707		2,912		193,083

Year ended December 31, 2008	124,736	59,231	186,063	5,053	375,083

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

	Successor	Predecessor		
	Period from Acquisition (May 26, 2010) to December 31, 2010 (in thousands)	Period from January 1, 2010 to Disposition (May 25, 2010)	Year Ended December 31, 2009 (in thousands)	Year Ended December 31, 2008
Net (loss) income from continuing operations before income taxes	$ (4,176)	$ (4,215)	$ 141,663	$ 87,131
Add (deduct):				
Operation and maintenance	77,808	47,842	117,080	119,715
General and administrative	43,739	37,212	57,863	51,323
Loss (gain) on assets sales	213	303	(133,282)	457
Management services termination fee				3,888
Transaction expenses				1,620
Depreciation and amortization	75,967	41,784	100,098	93,393
Income from unconsolidated subsidiaries	(53,493)	(15,872)	(7,886)	
Interest expense, net	48,251	34,541	77,665	62,940
Loss on debt refinancing, net	15,748	1,780		
Other income and deductions, net	8,229	3,897	15,132	(328)
Total segment margin	$ 212,286	$ 147,272	$ 368,333	$ 420,139

17. Equity-Based Compensation

The Partnership s LTIP for its employees, directors and consultants authorizes grants up to 3,565,584 common units. 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 $9,893,000 as a result of such unit vesting. LTIP compensation expense of $1,827,000, $12,070,000, $6,008,000 and $4,318,000 is recorded in general and administrative expense in the statement of operations for the periods from May 26, 2010 to December 31, 2010 and from January 1, 2010 to May 25, 2010, and for the years ended December 31, 2009 and 2008, respectively.

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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. The Partnership used the simplified method outlined in Staff Accounting Bulletin No. 107 for estimating the exercise behavior of option grantees, given the absence of historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its units have been publicly traded. 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, 2010, 2009, and 2008 is as follows.

2010

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at the beginning of period	306,651	$ 21.50		
Granted				
Exercised	(100,200)	20.60		$ 444
Forfeited or expired	(4,501)	23.73		
Outstanding at end of period	201,950	21.93	5.3	1,087
Exercisable at the end of the period	201,950			1,087

2009

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at the beginning of period	431,918	$ 21.31		
Granted				
Exercised				$
Forfeited or expired	(125,267)	20.87		
Outstanding at end of period	306,651	21.50	6.3	184
Exercisable at the end of the period	306,651			184

2008

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at the beginning of period	738,668	$ 21.05		
Granted				
Exercised	(245,150)	20.55		$ 1,719
Forfeited or expired	(61,600)	21.11		
Outstanding at end of period	431,918	21.31	7.3	
Exercisable at the end of the period	431,918			

* Intrinsic value equals 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.

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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 on NASDAQ. The restricted (non-vested) common unit activity for the years ended December 31, 2010, 2009, and 2008 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		

2009

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	704,050	$ 29.26
Granted	24,500	11.13
Vested	(176,291)	29.78
Forfeited or expired	(88,250)	27.96
Outstanding at the end of period	464,009	28.36

2008

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	397,500	$ 31.62
Granted	477,800	27.99
Vested	(90,500)	31.63
Forfeited or expired	(80,750)	30.66
Outstanding at the end of period	704,050	29.26

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 percent and the market condition grants vested at a rate of 150 percent pursuant to the terms of the awards.

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.

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.

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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.

The following table presents phantom unit activity for the year ended December 31, 2010 and 2009.

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

2009

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period		$
Service condition grants	133,480	13.43
Market condition grants	174,720	4.64
Vested service condition		
Vested market condition		
Forfeited service condition	(2,600)	12.46
Forfeited market condition	(3,900)	4.49
Total outstanding at end of period	301,700	8.63

The Partnership expects to recognize $14,340,000 of compensation expense related to non-vested phantom units over a period of 4.3 years.

18. Subsequent Events

On January 27, 2011, the Partnership declared a distribution of $0.445 per outstanding common unit and Series A Preferred Unit, including units equivalent to the General Partner s two percent interest in the Partnership, and an aggregate distribution of $1,051,000, with respect to incentive distribution rights, that was paid on February 14, 2011 to unitholders of record at the close of business on February 7, 2011.

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19. Quarterly Financial Data (Unaudited)

2010	Predecessor Quarter ended March 31 (in thousands except for earnings per unit)	Predecessor Period from April 1 to May 25	Successor Period from May 26 to June 30 (in thousands except for earnings per unit)	Successor Quarter ended September 30	Successor Quarter ended December 31
Operating revenues	$ 304,785	$ 200,265	$ 96,980	$ 296,888	$ 322,745
Operating income (loss)	18,405	1,726	(1,256)	(927)	16,742
Income (loss) from continuing operations	462	(5,081)	(4,981)	7,522	(7,269)
(Loss) income from discontinued operations	(912)	585	86	324	(1,654)
Net (loss) income attributable to Regency Energy Partners LP	(612)	(4,740)	(4,924)	7,788	(8,992)
Earnings per common units:					
Basic and diluted (loss) income from continuing operations per common unit	(0.02)	(0.07)	(0.05)	0.03	(0.07)
Basic and diluted (loss) income from discontinued operations per common unit	(0.01)	0.01	0.00	0.00	(0.01)
Basic and diluted net (loss) income per common unit	(0.03)	(0.07)	(0.05)	0.04	(0.09)

2009	Predecessor Quarter ended March 31 (in thousands except for earnings per unit)	Quarter ended June 30	Quarter ended September 30	Quarter ended December 31
Operating revenues	$ 279,201	$ 242,786	$ 238,940	$ 282,350
Operating income	163,210	23,277	22,210	17,877
Income (loss) from continuing operations	149,344	6,107	(10,081)	(2,612)
Loss from discontinued operations	(920)	(152)	(462)	(735)
Net income (loss) attributable to Regency Energy Partners LP	148,389	5,890	(10,504)	(3,377)
Earnings per common and subordinated units:				
Basic income (loss) from continuing operations per unit	1.86	0.07	(0.15)	(0.06)
Diluted income (loss) from continuing operations per unit	1.79	0.07	(0.15)	(0.06)
Basic and diluted loss from discontinued operations per unit	(0.01)	(0.00)	(0.01)	(0.01)
Basic net income (loss) per unit	1.85	0.07	(0.16)	(0.07)
Diluted net income (loss) per unit	1.78	0.06	(0.16)	(0.07)