Regency Energy Partners LP
Form 10-K
March 01, 2010
Table of Contents

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, 2009

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

(214) 750-1771

(Registrant s telephone number, including area code)

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units of Limited Partner Interests	**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 files). Yes ¨ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) 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, 2009, the aggregate market value of the registrant s common units held by non-affiliates of the registrant was $821,947,250 based on the closing sale price as reported on the NASDAQ Global Select Market.

There were 93,174,103 common units outstanding as of February 23, 2010.

DOCUMENTS INCORPORATED BY REFERENCE

None

Table of Contents

REGENCY ENERGY PARTNERS LP

ANNUAL REPORT ON FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2009

TABLE OF CONTENTS

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 to Regency Gas Services LLC, all the outstanding member interests of which were contributed to the Partnership on February 3, 2006, 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	Alinda Capital Partners LLC, a Delaware limited liability company that is an independent private investment firm specializing in infrastructure investments
Alinda Investor I	Alinda Gas Pipelines I, L.P., a Delaware limited partnership
Alinda Investor II	Alinda Gas Pipelines II, L.P., a Delaware limited partnership
Alinda Investors	Alinda Investor I and Alinda Investor II, collectively
ASC	ASC Hugoton LLC, an affiliate of GECC
Bbls/d	Barrels per day
Bcf	One billion cubic feet
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
Enbridge	Enbridge Pipelines (NE Texas), LP, Enbridge Pipeline (Texas Interstate), LP and Enbridge Pipelines (Texas Gathering), LP
EnergyOne	FrontStreet EnergyOne LLC
El Paso	El Paso Field Services, LP
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FASB ASC	FASB Accounting Standards Codification
FASB ASU	FASB Accounting Standards Update
FERC	Federal Energy Regulatory Commission
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
FrontStreet	FrontStreet Hugoton LLC, a wholly-owned subsidiary of the Partnership
GAAP	Accounting principles generally accepted in the United States
GE	General Electric Company
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer LP and Regency LP Acquirer 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
GSTC	Gulf States Transmission Corporation, a wholly-owned subsidiary of the Partnership
HLPSA	Hazardous Liquid Pipeline Safety Act
HM Capital Investors	Regency Acquisition LP, HMTF Regency L.P., HM Capital Partners and funds managed by HM Capital Partners, including Fund V, and certain Co-investors, including some of the directors and officers of the General Partner.
HM Capital Partners	HM Capital Partners LLC

Table of Contents

Name	Definition or Description
HPC	RIGS Haynesville Partnership Co., a general partnership that owns 100 percent of RIG
ICA	Interstate Commerce Act
IDRs	Incentive Distribution Rights
IPO	Initial Public Offering of Securities
IRS	Internal Revenue Service
Lehman	Lehman Brothers Holdings, Inc.
LIBOR	London Interbank Offered Rate
LTIP	Long-Term Incentive Plan
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
NAAQS	National Ambient Air Quality Standards
Nasdaq	Nasdaq Stock Market, LLC
Nexus	Nexus Gas Holdings, LLC
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids, including ethane, propane, butane and natural gasoline
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968, as amended
NOE	Notice of Enforcement
NPDES	National Pollutant Discharge Elimination System
NYMEX	New York Mercantile Exchange
OSHA	Occupational Safety and Health Act
Partnership	Regency Energy Partners LP
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
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, a wholly-owned subsidiary of HPC, which was converted from Regency Intrastate Gas LLC upon HPC formation
RIGS	Regency Intrastate Gas System
SCADA	System Control and Data Acquisition
SEC	Securities and Exchange Commission
Sonat	Southern Natural Gas Company
TCEQ	Texas Commission on Environmental Quality
Tcf	One trillion cubic feet
Tcf/d	One trillion cubic feet per day
TexStar	TexStar Field Services, L.P. and its general partner, TexStar GP, LLC
TRRC	Texas Railroad Commission
WTI	West Texas Intermediate Crude

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 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, pl expect, continue, estimate, goal, forecast, may or similar expressions help identify

Table of Contents

forward-looking statements. Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we cannot give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions, including without limitation the following:

- volatility in the price of oil, natural gas, and natural gas liquids;
- declines in the credit markets and the availability of credit for us as well as for producers connected to our system and our customers;
- 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;
- 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.

Table of Contents

Item 1. Business

OVERVIEW

We are a growth-oriented publicly-traded Delaware limited partnership, formed in 2005, engaged in the gathering, processing, contract compression and transportation of natural gas and NGLs. We provide these services through systems located in Louisiana, Texas, Arkansas, Pennsylvania and the mid-continent region of the United States, which includes Kansas, Colorado, and Oklahoma. Our midstream assets are located in historically well-established areas of natural gas production that have been characterized by long-lived, predictable reserves.

We divide our operations into four 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 43 percent interest in HPC, which, through RIGS, delivers natural gas from northwest Louisiana to markets as well as downstream pipelines in northeast Louisiana through a 450 mile intrastate pipeline system;

- *Contract Compression*: We provide turn-key natural gas compression services whereby we guarantee our customers 98 percent mechanical availability of our compression units for land installations and 96 percent mechanical availability for over-water installations; and

- *Corporate and Others*: We own and operate an interstate pipeline that consists of 10 miles of pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana. This pipeline has a FERC certificated capacity of 150 MMcf/d.

The following map depicts the geographic areas of our operations.

Table of Contents

RECENT DEVELOPMENTS

Subsequent to December 31, 2009, our Contract Compression segment placed in service approximately 3,000 revenue generating horsepower in Pennsylvania to compress natural gas in the Marcellus Shale and we are currently working with customers as to the timing of placing in service an additional revenue generating horsepower of approximately 4,000 in 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 and treating, fractionation, and transportation. Raw natural gas produced from the wellhead is gathered and often delivered to a plant located near the production, where it is treated, dehydrated, and/or processed. Natural gas processing involves the separation of raw natural gas into pipeline quality natural gas, principally methane, and mixed NGLs. Natural gas treating entails the removal of impurities, such as water, sulfur compounds, carbon dioxide and nitrogen. Pipeline-quality natural gas is delivered by interstate and intrastate pipelines to markets. Mixed NGLs are typically transported via NGL pipelines or by truck to fractionators, which separates the NGLs into their components, such as ethane, propane, normal butane, isobutane and natural gasoline. The NGL components are then sold to end users.

The following diagram depicts our role in the process of gathering, processing, compression and transporting 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 through-put 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.

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.

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

Table of Contents

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.

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, utilities and other pipelines.

Overview of U.S. market. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas wells. Natural gas remains a critical component of energy consumption in the United States. According to the EIA, total annual production of natural gas is expected to increase 14 percent from 20.6 Tcf in 2008 to 23.3 Tcf in 2035. Natural gas production from shale formations is expected to grow to 6.0 Tcf by 2035, more than offsetting the decline in conventional production. EIA projects that natural gas and renewable power plants will account for the majority of electricity generation capacity addition by 2035.

Short-Term Energy Outlook. At December 31, 2009, the working natural gas drilling rig count totaled 759 compared to 665 in mid July of 2009, a 14 percent increase. EIA expects a 3 percent decline in natural gas production in 2010 due to the natural decline in existing well production and the lagged effect of reduced drilling. EIA also expects production to increase by 1.3 percent in 2011. Demand for natural gas in 2010 is expected to remain unchanged. EIA expects that higher prices for natural gas in 2010 will drive lower consumption in the electric power generation sector by 2.8 percent; this decline is expected to be offset by growth in the residential, commercial and industrial sectors. EIA projects that natural gas consumption in 2011 will increase by 0.4 percent, led by a 2.5 percent increase in consumption in the industrial sector. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

EIA forecasts demand for crude oil and NGLs to increase in years 2010 and 2011. Total petroleum consumption is forecasted to increase by 1.1 percent in 2010, with all of the major sectors contributing to this increase.

GATHERING AND PROCESSING OPERATIONS

General. We operate gathering and processing assets in five geographic regions of the United States: north Louisiana, the mid-continent region of the United States, and east, south and west Texas. We contract with producers to gather raw natural gas from individual wells or central delivery 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, 2009.

Region	Pipeline Length (Miles)	Plants	Compression (Horsepower)
North Louisiana	407	4	58,937
East Texas	371	1	20,009
South Texas	541	2	24,779
West Texas	806	1	58,008
Mid-Continent	3,470	1	43,519
Total	5,595	9	205,252

North Louisiana Region. Our north Louisiana region assets include:

- Two cryogenic natural gas processing facilities;

- A large integrated natural gas gathering and processing system located primarily in four parishes (Claiborne, Union, Lincoln, and Ouachita) of north Louisiana;

- The Logansport Gathering System, which provides natural gas gathering, dehydration and compression services for producers in Shelby County, Texas and Desoto Parish, Louisiana. In 2009, we announced Logansport Expansion Phase I, a $47,000,000 extension of the Logansport Gathering System in north Louisiana, and Logansport Expansion Phase II, a $40,000,000 expansion to gather gas from acreage dedicated to Logansport Expansion Phase I. Logansport Expansion Phase I is expected to add approximately 485 MMcf/d of gathering capacity and add approximately 300 MMcf/d of new delivery interconnect capacity to CenterPoint Gas Transmission s Line CP. Logansport Expansion Phase II includes the construction of an amine treating plant with capacity of 300 MMcf/d, approximately 15 miles of gathering lines and expanded interconnect capacity at Tennessee Gas Pipeline and Crosstex LIG, LLC by 100 MMcf/d and 35 MMcf/d, respectively. The Logansport Expansion Phase I and II projects are expected to be completed during 2010; and

- A refrigeration plant located in Bossier Parish and a conditioning plant 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 and transportation.

East Texas Region. Our east Texas assets gather, compress, process and dehydrate natural gas through a large integrated natural gas gathering and processing system located in Rains, Wood, Van Zandt, Henderson, Franklin, and Hopkins counties that delivers natural gas to our east Texas processing plant. Our east Texas processing plant is a cryogenic natural gas processing plant that was constructed in Henderson County, Texas in

Table of Contents

1981. It includes an amine treating unit, a cryogenic NGL recovery unit, a nitrogen rejection unit, and a liquid sulfur recovery unit. This plant removes hydrogen sulfide, carbon dioxide and nitrogen from the natural gas stream, recovers NGLs and condensate, delivers pipeline quality natural gas at the plant outlet and produces sulfur.

The natural gas supply for our east Texas gathering systems comes primarily from natural gas wells that are located in a mature basin that generally have long lives, predictable gas flow rates, and high levels of hydrogen sulfide.

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.

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 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

Table of Contents

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.

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

Transportation. We own a 43 percent interest in HPC which, through RIGS, delivers natural gas from northwest Louisiana to markets as well as downstream pipelines in northeast Louisiana through a 450 mile intrastate pipeline system known as RIGS. The construction and development of the expansion of RIGS (Haynesville Expansion Project) was completed in January 2010 and added 1.1 Bcf/d of capacity and 14,200 horsepower of compression. In September 2009, HPC announced plans to construct a $47,000,000 pipeline extension of the Haynesville Expansion Project (the Red River Lateral). The Red River Lateral was also completed in January 2010, adding an additional 100 MMcf/d of capacity, bringing RIGS total capacity to 2.1 Bcf/d.

RIGS consists of an intrastate pipeline ranging from 4 to 42 inches in diameter that extends across north Louisiana from Caddo Parish to Franklin Parish and, with the completion of the Red River Lateral, extends into Red River Parish. In addition to the Haynesville Shale production, RIGS transports natural gas produced from the Vernon field, the Elm Grove field and the Sligo field. The transportation operations are located in areas that have experienced significant levels of drilling activity, providing RIGS with opportunities to access newly developed natural gas supplies.

Substantially all of the incremental capacity from Haynesville Expansion Project and Red River Lateral has been contracted to third parties under firm transportation agreements with 10-year terms, whereby approximately 85 percent of total revenues from these system expansions will be derived from reservation fees.

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.

Table of Contents

The following tables set forth certain information regarding contract compression s third-party revenue generating horsepower as of December 31, 2009 and 2008.

		December 31, 2009	
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	65,397	9%	361
500-999	74,826	10%	121
1,000+	613,105	81%	405
	753,328	100%	887

		December 31, 2008	
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	59,288	7%	351
500-999	83,299	11%	134
1,000+	636,080	82%	425
	778,667	100%	910

CORPORATE AND OTHERS

Gulf States Transmission. Our interstate pipeline, owned and operated by GSTC, consists of 10 miles of 12 and 20 inch diameter pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana. The pipeline has a FERC certificated capacity of 150 MMcf/d.

OUR CONTRACTS

The table below provides the margin by product and percentage for the years ended December 31, 2009 and 2008.

Margin by Product	2009	2008
Net Fee	71%	64%
NGL	20	18
Gas	4	10
Condensate	5	5
Helium and Sulphur		3
Total	100%	100%

Gathering and Processing Contracts. We contract with producers to gather raw natural gas from individual wells or central receipt points located near our gathering systems and processing plants. Following the execution of a contract with the producer, we connect the producer s wells or central receipt points to our gathering lines through which the natural gas is delivered to a processing plant owned and operated by us or a third party. We obtain supplies of raw natural gas for our gathering and processing facilities under contracts having terms ranging from month-to-month to life of the lease. We categorize our processing contracts in increasing order of commodity price risk as fee-based, percentage-of-proceeds, or keep-whole contracts. For a description of our fee-based arrangements, percent-of-proceeds arrangements, and keep-whole arrangements, please read Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Our Operations.

7

Table of Contents

During the year ended December 31, 2009, purchases in our gathering and processing segment from one producer represented 23 percent of the cost of gas and liquids in our consolidated statement of operations.

We also perform a producer service function. We purchase natural gas from producers or gas marketers at receipt points or plant tailgates at an adjusted market price and sell the natural gas at market price.

Transportation Contracts. HPC, through RIGS, provides natural gas transportation services pursuant to contracts with natural gas shippers. These contracts are all fee-based. Generally, the transportation services are of two types: firm transportation and interruptible transportation. When RIG agrees to provide firm transportation service, it becomes obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation, the shipper pays a specified reservation charge, whether or not the capacity is utilized by the shipper, and in some cases the shipper also pays a commodity charge with respect to quantities actually shipped. When RIG agrees to provide interruptible transportation service, it becomes obligated to transport natural gas nominated and actually delivered by the shipper only to the extent that RIG has available capacity. The shipper pays no reservation charge for this service but pays a commodity charge for quantities actually shipped. RIG provides its transportation services for intrastate transportation under the negotiated terms of the contracts and under an operating statement that it has filed and maintains with the FERC with respect to transportation authorized under Section 311 of the NGPA.

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. 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.

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);
- *East Texas:* Enbridge Energy Partners LP and Eagle Rock Energy Partners, L.P.;
- *South Texas:* Enterprise Products Partners LP and DCP Midstream Partners, L.P;
- *West Texas:* Southern Union Gas Services and Enterprise Products Partners LP; and
- *Mid-Continent:* DCP Midstream Partners, L.P., ONEOK Energy Marketing and Trading, L.P., and Penn Virginia Corporation.

8

Table of Contents

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. In transporting natural gas across north Louisiana, HPC, through RIGS, typically receives gas from gathering facilities and delivers gas to intrastate and interstate markets. RIG competes with interstate and intrastate pipelines that have access to the same gathering facilities or production areas. RIG 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 Energy Transfer Partners LP, Enbridge Energy Partners LP, and Enterprise Products Partners LP.

Contract Compression. The 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, and J-W Operating Company.

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.

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 a series of swap contracts for individual NGLs, natural gas, and WTI crude oil. 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.

Our contract compression business does not have direct exposure to natural gas commodity price risk because we do not take title to the natural gas we compress and because the natural gas we use as fuel for our compressors is supplied by our customers without cost to us.

Table of Contents

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. Louisiana also has agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers. RIG transports interstate natural gas in Louisiana for many of its shippers pursuant to Section 311 of the NGPA. To the extent that RIG 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. 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 the Haynesville Expansion Project and Red River Lateral. The rates are effective February 1, 2010, but subject to refund with interest.

FERC is continually proposing and implementing new rules and regulations affecting Section 311 transportation. FERC has adopted new regulations requiring certain major non-interstate 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 District of Columbia Circuit, the posting requirements impose increased costs and administrative burdens on intrastate pipelines, including RIGS owned by HPC. FERC has also proposed regulations requiring intrastate pipelines providing NGPA Section 311 transportation service to submit to FERC and post quarterly transactional reports publicly. This would involve publicly disclosing the primary commercial terms of RIG s contracts, including shipper name, contract length, rates charged, and points of receipt and delivery. Such regulations would impose additional regulatory burdens and costs on RIG and require the release of commercially-sensitive customer information. Since any new regulations would also be required of competitors providing Section 311 service, we do not believe new regulations would place RIG at a disadvantage vis-à-vis its competitors.

Interstate Natural Gas Pipeline Regulation. FERC also has broad regulatory authority over the business and operations of interstate natural gas pipelines, such as the pipeline owned by our subsidiary, GSTC. 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 to refund with interest. GSTC holds a FERC-approved tariff setting forth cost-based rates, terms and conditions for services to shippers wishing to take interstate transportation service. 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;

Table of Contents

- depreciation and amortization policies;
- accounting rules for ratemaking purposes;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- prevention of market manipulation in connection with interstate sales, purchases, or transportation of natural gas; and
- information posting requirements.

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

FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. We do not believe that we will be affected by any such FERC action in a manner materially different than any other natural gas companies with which we compete.

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 District of Columbia 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 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. For example, in 2006, the TRRC approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines that prohibit such entities from unduly discriminating in favor of their affiliates.

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 whole-sale 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.

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, 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

Table of Contents

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.

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 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.

Assets Acquired from El Paso. Under the agreement pursuant to which our operating partnership acquired assets from El Paso Field Services LP and its affiliates in 2003, an escrow account of $9,000,000 relating to claims, including environmental claims, was established. After the time of this agreement, a Final Site Investigation Report was prepared. Based on this additional investigation, environmental issues were determined to exist with respect to a number of our facilities.

In January 2008, pursuant to authorization by the Board of Directors of the General Partner, the Partnership agreed to partially settle the El Paso environmental remediation claims. Under the settlement, El Paso agreed to clean up and obtain no further action letters from the relevant state agencies for three Partnership-owned facilities. El Paso is not obligated to clean up properties leased by the Partnership, but it has indemnified the Partnership for pre-closing environmental liabilities. All sites for which the Partnership made environmental claims against El Paso are either addressed in the settlement or have already been resolved. In May 2008, the Partnership released all but $1,500,000 from the escrow fund maintained to secure El Paso s obligations. This amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion.

West Texas Assets. A Phase I environmental study was performed on certain assets located in west Texas in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made against the Partnership with respect to environmental issues at the west Texas assets or under the policy.

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 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.

Clean Water Act. The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including natural gas liquid-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. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere and other climate changes. In response to such studies, President Obama has expressed support for and Congress is considering a variety of legislation to reduce emissions of greenhouse gases. Two of the bills, H.R. 2454 and S. 1733, employ a market-based cap-and-trade program, among other provisions, to reduce over time the emissions of greenhouse gases. The US House of Representatives approved H.R. 2454 on June 25, 2009. The Senate Environment and Public Works Committee adopted S. 1733 on November 5, 2009, but the bill has not yet been presented to the Senate for a vote. A cap-and-trade program could impose on us costs associated with the purchase of allowances or credits or costs associated with additional controls to manage emissions from our existing sources. An alternative bill, the Carbon Limits and Energy for America s Renewal Act (CLEAR), was introduced in the Senate on December 9, 2009, and proposes to regulate the amount of fossil fuel carbon (defined to include natural gas) that producers and importers can introduce into domestic commerce. If enacted, CLEAR would require an entity in the business of producing fossil carbon to purchase the right to sell or otherwise place fossil carbon into commerce in the United States and also would reduce over time the total amount of fossil carbon that could be sold into domestic commerce. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. These cap and trade programs could require major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and, on an annual basis, surrender emission allowances. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations (*e.g.* , compressor stations) or from the combustion of fuels (*e.g.* , natural gas) we process.

In response to the United States Supreme Court s holding in the 2007 decision, *Massachusetts, et al. v. EPA* (that carbon dioxide may be regulated as an air pollutant under the federal Clean Air Act), in December 2009,

Table of Contents

EPA issued its Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act (Endangerment Finding)), which found that greenhouse gas emissions endanger the public health and welfare and that the combined emissions of greenhouse gases from new motor vehicles contribute to global climate change. The Endangerment Finding does not itself impose any requirements on industry or other entities. It does, however, pave the way for EPA to finalize proposed greenhouse gas emission standards for motor vehicle sources which, in turn, could trigger stationary source controls under the Clean Air Act. Several parties have requested review of the Endangerment Finding with the U.S. Court of Appeals for the D.C. Circuit, but we cannot predict the outcome of the court s review. In contemplation of the regulation of greenhouse gases emissions from stationary sources, in September 2009 EPA proposed new applicability thresholds for greenhouse gas emissions under the Clean Air Act s Prevention of Significant Deterioration and Title V Operating Permit programs (Tailoring Rule). If promulgated as proposed, the Tailoring Rule would impose additional permitting requirements and the installation of best available control technology on new or modified stationary sources that emit more than 25,000 tons of carbon dioxide equivalent emissions annually. Any regulation of greenhouse gas emissions from stationary sources could apply to our processing, treating compression and pipeline facilities.

In addition, on January 19, 2010, EPA published a proposed rule that would reduce the NAAQS for ozone set in 2008 from 0.075 parts per million (ppm) to within the range of 0.060 to 0.070 ppm. Areas within states that we operate may not comply with the proposed NAAQS for ozone and, for those areas of nonattainment, states may adopt plans, known as State Implementation Plans, which could require new and modified sources of emissions to demonstrate compliance with allowable limits and may impose additional controls on our existing sources of ozone emissions.

It is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, but any such future laws and regulations could result in a potential decline in the production of natural gas, increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business or demand for the natural gas we gather and process.

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.

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 which 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.

Table of Contents

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 recently proposed 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, implement and submit written control room management procedures and to conduct baseline point by point verifications and periodic testing of a pipeline s SCADA system. When adopted, the new regulations may increase regulatory burdens and administrative costs for the Partnership.

TCEQ Notice of Enforcement. In February 2008, the TCEQ issued a NOE concerning one of the Partnership s processing plants located in McMullen County, Texas. The NOE alleged that, between March 9, 2006, and May 8, 2007, this plant experienced 15 emission events of various durations from four hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. In January 2010, the TCEQ notified us in writing that it had concluded that there had been no violation and that the TCEQ would take no further action.

EMPLOYEES

As of December 31, 2009, our General Partner employed 761 employees, of whom 520 were field operating employees and 241 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 annual and quarterly financial reports, current-event reports as well as interim updates of a material nature to investors with the Securities and Exchange Commission. You may read and copy any of these materials at the SEC s Public Reference Room at 100 F. Street, NE, Washington, DC 20549. Information on the operation of the Public Reference Room is available by calling the SEC at 1-800-SEC-0330. Alternatively, the SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of that site is http://www.sec.gov.

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, the website. Therefore, such information should not be considered part of this report.

Table of Contents

Item 1A. Risk Factors

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;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the level of capital expenditures we make;
- the cost of acquisitions, if any; and
- the amount of cash reserves established by our General Partner.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, which will be affected by non-cash items and not solely on profitability. 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.

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 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 through-put 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 processing facilities and pipeline transportation systems, which would lead to reduced utilization of these assets. 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. For example, companion Senate and House bills to amend the Safe Drinking Water Act were introduced in Congress in June 2009. The proposed legislation would require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could result in a decrease in our customers exploration and production activities, resulting in lower volumes of natural gas production, which could result in a decline in the demand for our services.

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, through-put 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 the current deterioration in 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. Recently, there has been a significant decline in the credit markets and the availability of credit. 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 and contract compression revenue. 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 a 43 percent equity interest in HPC and we do not exercise control over HPC.

We own a 43 percent ownership interest in HPC and we have the right to appoint one member of the four member management committee. 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: merger or consolidation of the joint venture, sale of all or substantially all of the assets of the joint venture, 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.

Table of Contents

We may be required to make additional capital contributions to HPC.

The HPC management committee may request that we make additional capital contributions to support its 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 venture 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 two vendors, Spitzer Industries Corp. and Standard Equipment Corp., 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.

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. 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, isobutane, 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

Table of Contents

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.

In addition, proposed derivatives legislation in the U.S. Congress would impose limits, substantial costs and burdens on participants in the over-the-counter derivatives markets, which could restrict our use of hedges in the future and adversely affect our cash flows.

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 revenue 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 our Haynesville 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.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and current weak economic conditions have affected, and will likely continue to affect, our ability to obtain funding.

The availability of funds from the debt and equity markets generally has diminished. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers.

In addition, because of the recent downturn in the financial markets, including the issues surrounding the solvency of many institutional lenders and the recent failure of several banks, our ability to obtain capital from

Table of Contents

our credit facility may be impaired. For example, as a result of Lehman Brothers Holding, Inc., or Lehman, filing a petition under Chapter 11 of the U.S. Bankruptcy Code, a subsidiary of Lehman that is a committed lender under our credit facility has declined requests to honor its commitment to lend under our credit facility. As of December 31, 2009, the unfunded commitment from Lehman was $10,675,000, thereby effectively reducing the amount available to us under our credit facility to $889,325,000. We may be unable to utilize the full borrowing capacity under our credit facility if other lenders are not willing to provide additional funding to make up the portion of the credit facility commitments that Lehman s subsidiary has refused to fund or if any of the remaining committed lenders is unable or unwilling to fund their respective portion of any funding request we make under our credit facility.

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, 2009 was 44 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 indenture for our senior notes, may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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

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

The interest rate on our senior notes is 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 indenture 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.

Table of Contents

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 pipeline owned by our subsidiary, GSTC. GSTC holds a FERC-approved tariff 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 RIG. 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 GSTC or RIG 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.

As limited partnership entities, neither we nor our regulated pipelines, including RIGS, 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. In connection with its January 28, 2010 Section 311 rate case (see below), RIG may be required to demonstrate the extent to which inclusion of an income tax allowance in its cost-of-service is permitted under the current income tax allowance policy. 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.

Table of Contents

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 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.

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.

Our ability to recover the costs of the Haynesville Expansion Project will depend upon RIG s success in recovering these costs in a new rate proceeding with the Federal Energy Regulatory Commission and under the contracts with shippers.

The expansion phase of RIGS in North Louisiana was placed in service on January 27, 2010. At that time, RIG filed and implemented revised rates with FERC, the design of which will reflect the costs of and contracts for the use of this expansion capacity, and FERC may elect to review the rates under Section 311 of the Natural Gas Policy Act. The ability of RIG to charge rates that allow it to recover these costs, including a return on its capital, will depend on the outcome of any rate proceeding. We cannot assure you that RIG will be successful in such a proceeding. If FERC requires adjustments, including potential refunds, to the revised transportation rate, or if any contract rates to which RIG has agreed are below the maximum rates we otherwise could charge, our cash flows and ability to make distributions may be adversely affected.

Table of Contents

On January 28, 2010, RIG filed a rate case with FERC to implement significantly increased maximum rates for Section 311 transportation services provided by RIG effective February 1, 2010, to recover the costs of operating the RIGS pipeline system. The rate case reflects a substantial increase in the rate base of RIG, as well as increased costs, including return and income taxes, arising from the Haynesville Expansion Project and Red River Lateral. FERC will review the rates to determine whether they are fair and equitable and not in excess of an amount reasonably comparable to the rates that interstate pipelines would be permitted to charge for providing similar services. While RIG s shippers are subject, in large part, to fixed or capped rates, FERC may still undertake a comprehensive review of the new rates and RIG s operations and terms of service. FERC has the statutory authority to require a refund, with interest, of RIG s rates from February 1, 2010. The timing and outcome of this proceeding is uncertain, and it could have a material adverse affect on HPC, the owner of RIGS, and our results of operations and business through our 43 percent interest in HPC.

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 businesses, 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 businesses;
- 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 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;
- inadvertent damage from construction and farm equipment;
- 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;

Table of Contents

- weather related hazards, such as hurricanes and extensive rains which could delay the construction of assets and extreme cold which can 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 through-put 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.

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.

We currently estimate that we will incur costs of $604,000 in 2010 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.

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

Table of Contents

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 an accidental release of hazardous substances 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.

Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere and other climate changes. In response to such studies, President Obama has expressed support for and Congress is considering a variety of legislation to reduce emissions of greenhouse gases Two of the bills, H.R. 2454 and S. 1733, employ a market-based cap-and-trade program, among other provisions, to reduce over time the emissions of greenhouse gases. The US House of Representatives approved H.R. 2454 on June 25, 2009. The Senate Environment and Public Works Committee adopted S. 1733 on November 5, 2009, but the bill has not yet been presented to the Senate for a vote. A cap-and-trade program could impose on us costs associated with the purchase of allowances or credits or costs associated with additional controls to manage emissions from our existing sources. An alternative bill, the Carbon Limits and Energy for America s Renewal Act (CLEAR), was introduced in the Senate on December 9, 2009, and proposes to regulate the amount of fossil fuel carbon (defined to include natural gas) that producers and importers can introduce into domestic commerce. If enacted, CLEAR would require an entity in the business of producing fossil carbon to purchase the right to sell or otherwise place fossil carbon into commerce in the United States and also would reduce over time the total amount of fossil carbon that could be sold into domestic commerce. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. These cap and trade programs could require major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and, on an annual basis, surrender emission allowances. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations (*e.g.* , compressor stations) or from the combustion of fuels (*e.g.* , natural gas) we process.

In response to the United States Supreme Court s holding in the 2007 decision, *Massachusetts, et al. v. EPA* (that carbon dioxide may be regulated as an air pollutant under the federal Clean Air Act), in December 2009, EPA issued its Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act (Endangerment Finding), which found that greenhouse gas emissions endanger the public health and welfare and that the combined emissions of greenhouse gases from new motor vehicles contribute to global climate change. The Endangerment Finding does not itself impose any requirements on industry or other entities. It does, however, pave the way for EPA to finalize proposed greenhouse gas emission standards for motor vehicle sources which, in turn, could trigger stationary source controls under the Clean Air Act. Several parties have requested review of the Endangerment Finding with the U.S. Court of Appeals for the D.C. Circuit, but we cannot predict the outcome of the court s review. In contemplation of the regulation of greenhouse gases emissions from stationary sources, in September 2009 EPA proposed new applicability thresholds for greenhouse gas emissions under the Clean Air Act s Prevention of Significant Deterioration and Title V Operating Permit programs (Tailoring Rule). If promulgated as proposed, the Tailoring Rule would impose additional permitting requirements and the installation of best available control technology on new or modified stationary sources that emit more than 25,000 tons of carbon dioxide equivalent emissions annually. These proposed rules could go into effect during 2010. Any regulation of greenhouse gas emissions from stationary sources could apply to our processing, treating compression and pipeline facilities.

In addition, on January 19, 2010, EPA published a proposed rule that would reduce the NAAQS for ozone set in 2008 from 0.075 parts per million (ppm) to within the range of 0.060 to 0.070 ppm. Areas within states that we operate may not comply with the proposed NAAQS for ozone and, for those areas of nonattainment, states may adopt plans, known as State Implementation Plans, which could require new and modified sources of emissions to demonstrate compliance with allowable limits and may impose additional controls on our existing sources of ozone emissions.

It is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, but any such future laws and regulations could result in a potential decline in the production of natural gas, increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business or demand for the natural gas we gather and process.

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 the 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.

Table of Contents

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.

RISKS RELATED TO OUR STRUCTURE

GE EFS controls our General Partner, which has sole responsibility for conducting our business and managing our operations.

Although our General Partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner beneficial to its owner, GE EFS. Conflicts of interest may arise between GE EFS, including our General Partner, on the one hand, and us, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires GE EFS or affiliates of GECC to pursue a business strategy that favors us;
- our General Partner is allowed to take into account the interests of parties other than us, such as GE EFS, in resolving conflicts of interest;
- our General Partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings and repayments of debt, issuance of additional partnership securities, and cash reserves, each of which can affect the amount of cash available for distribution;
- our General Partner determines which costs incurred are reimbursable by us;
- our partnership agreement does not restrict our General Partner from causing us to pay for any services rendered to us or entering into additional contractual arrangements with any of its affiliates on our behalf;

Table of Contents

- our General Partner intends to limit its liability regarding our contractual and other obligations; and
- our General Partner controls the enforcement of obligations owed to us by our General Partner.

GE EFS and other affiliates of GECC may compete directly with us.

GE EFS and other affiliates of GECC are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. GE EFS and its affiliates currently own various midstream assets and conduct midstream businesses that may potentially compete with us. In addition, GE EFS and its affiliates may acquire, construct or dispose of any additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct or dispose of those assets.

Our reimbursement of our general partner s expenses will reduce our cash available for distribution to common unitholders.

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

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

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

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

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

Table of Contents

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 23, 2010 our General Partner owned 26.5 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 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 your approval, which would dilute your existing ownership interest.

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 you to sell your units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 80 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

Table of Contents

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 23, 2010 our General Partner owned 26.5 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.

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 you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you 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 you.

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.

Table of Contents

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 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 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

Table of Contents

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.

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 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, which are located in Texas, Louisiana, Oklahoma, 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

Table of Contents

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. In 2009, we contributed the pipelines in our transportation segment to HPC.

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 Shreveport, Louisiana, and Midland, Houston, Victoria and San Antonio, Texas and Damascus, 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, including RGS, is, however, currently a party to any pending or, to our knowledge, threatened material legal or governmental proceedings, including proceedings under any of the various environmental protection statutes to which it is subject.

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.

Item 4. Reserved

Table of Contents

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 23, 2010, the number of holders of record of common units was 170, with 66,899,318 units held in street name. Currently, our common units are listed on the Nasdaq Global Select Market. 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		Cash Distributions
	High	Low	(per unit)
2010			
January 1, 2010 through February 23, 2010	23.50	19.71	(1)
2009			
First Quarter	12.89	8.08	0.4450
Second Quarter	14.68	11.00	0.4450
Third Quarter(2)	19.65	14.07	0.4450
Fourth Quarter(2)	21.00	18.56	0.4450
2008			
First Quarter(3)(4)	34.84	25.78	0.4000
Second Quarter(3)	28.73	23.93	0.4200
Third Quarter(3)	26.88	15.75	0.4450
Fourth Quarter(3)	19.00	4.92	0.4450

(1) The cash distribution for the first quarter of 2010 will be determined in April 2010.

(2) Excludes the Series A Redeemable Cumulative Convertible Preferred Units (Series A Preferred Units) which will receive fixed quarterly cash distributions of $0.445 beginning with the quarter ending March 31, 2010.

(3) Excludes the Class D common units which were not entitled to any distributions until they were converted into common units. The Class D common units converted to common units on February 9, 2009.

(4) Excludes the Class E common units which were not entitled to any distributions until they were converted into common units. The Class E common units converted to common units on May 5, 2008.

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.

Table of Contents

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.

		Marginal Percentage Interest in Distributions		
	Quarterly Distribution Per Unit Target Amount	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.

Table of Contents

Item 6. Selected Financial Data

The historical financial information presented below for the Partnership was derived from our audited consolidated financial statements as of December 31, 2009, 2008, 2007, 2006 and 2005. See Item 7 Management s Discussions and Analysis of Financial Condition and Results of Operations History of the Partnership and its Predecessor for a discussion of why our results may not be comparable, either from period to period or going forward.

	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
			(in thousands except per unit data)		
Statement of Operations Data:					
Total revenue	$ 1,089,497	$ 1,863,804	$ 1,190,238	$ 896,865	$ 709,401
Total operating expense	864,861	1,699,831	1,130,874	857,005	695,366
Operating income	224,636	163,973	59,364	39,860	14,035
Other income and deductions					
Income from unconsolidated subsidiary	7,886				
Interest expense, net	(77,996)	(63,243)	(52,016)	(37,182)	(17,880)
Loss on debt refinancing			(21,200)	(10,761)	(8,480)
Other income and deductions, net	(15,132)	332	1,252	839	733
Net income (loss) from continuing operations	139,394	101,062	(12,600)	(7,244)	(11,592)
Discontinued operations					732
Income tax (benefit) expense	(1,095)	(266)	931		
Net income (loss)	140,489	101,328	(13,531)	(7,244)	(10,860)
Net income attributable to noncontrolling interest	91	312	305		
Net income (loss) attributable to Regency Energy Partners LP	$ 140,398	$ 101,016	$ (13,836)	$ (7,244)	$ (10,860)
Less:					
Net income through January 31, 2006				1,564	
Net income (loss) for partners	$ 140,398	$ 101,016	$ (13,836)	$ (8,808)	
Amounts attributable to Series A convertible redeemable preferred units	3,995				
General partner's interest, including IDR	5,252	4,303	(366)	(164)	
Amount allocated to non-vested common units	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 partner interest	$ 129,366	$ 88,645	$ (20,544)	$ (11,235)	
Basic net income (loss) per common and subordinated unit	$ 1.61	$ 1.34	$ (0.40)	$ (0.29)	
Diluted net income (loss) per common and subordinated unit	1.60	1.28	(0.40)	(0.29)	
Cash distributions declared per common and subordinated unit	1.78	1.71	1.52	0.9417	
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		

41

Table of Contents

	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007 (in thousands)	Year Ended December 31, 2006	Year Ended December 31, 2005
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 1,456,435	$ 1,703,554	$ 913,109	$ 734,034	$ 609,157
Total assets	2,533,414	2,458,639	1,278,410	1,013,085	806,740
Long-term debt (long-term portion only)	1,014,299	1,126,229	481,500	664,700	428,250
Series A convertible redeemable preferred units	51,711				
Partners' capital and noncontrolling interest	1,243,010	1,099,413	568,186	212,657	230,962
Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$ 143,960	$ 181,298	$ 79,529	$ 44,156	$ 37,340
Investing activities	(156,165)	(948,629)	(157,933)	(223,650)	(279,963)
Financing activities	21,433	734,959	99,443	184,947	242,949
Other Financial Data:					
Adjusted total segment margin[1]	$ 379,411	$ 440,763	$ 228,652	$ 153,919	$ 88,022
Adjusted EBITDA[1]	205,160	254,473	142,234	92,811	51,230
Maintenance capital expenditures	20,170	18,247	8,764	16,433	9,158

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

Non-GAAP Financial Measures

We include 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 plus interest expense, provision for income taxes and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus non-cash loss (gain) from derivatives, (gain) loss on asset sales, net, loss on debt refinancing, other (income) expense, net, and the Partnership s interest in adjusted EBITDA from unconsolidated subsidiaries less income from unconsolidated subsidiary. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements such as investors, commercial 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.

Adjusted EBITDA is one of the critical inputs to the financial covenants within our credit agreement. The rates we pay for borrowings against this facility are determined by the ratio of our debt to adjusted EBITDA and by the ratio of our adjusted EBITDA to our interest expense. The calculation of these ratios allows for further pro forma adjustments to adjusted EBITDA for recent acquisitions, dispositions, and significant expansion projects. Based on the results of these ratios at the end of each reporting period, the credit spread on LIBOR borrowings will range from 3.25 percent to 2.5 percent. Our current credit spread is 3 percent. An event of default would occur if our debt to adjusted EBITDA was greater than 5.25, or if our adjusted EBITDA was less than 2.75 times interest expense. The credit agreement and associated amendments are filed as an exhibit to this Form 10-K.

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

Table of Contents

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 our Gathering and Processing segment margin and Corporate and Others segment margin as our revenue 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 our contribution of RIGS to HPC, we calculated our Transportation segment margin as revenue generated by fee income as well as, in those instances in which we purchased and sold gas for our account, gas sales revenue minus the cost of natural gas that we purchased and transported. After our contribution of RIGS to HPC, 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 an unconsolidated subsidiary.

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

We calculate total segment margin as the total of segment margin of our four segments, less the intersegment elimination. We define adjusted total segment margin as total segment margin adjusted for non-cash (gains) losses from derivatives.

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 results 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 or 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.

Table of Contents

	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007 (in thousands)	Year Ended December 31, 2006	Year Ended December 31, 2005
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and to net income (loss)					
Net cash flows provided by operating activities	$ 143,960	$ 181,298	$ 79,529	$ 44,156	$ 37,340
Add (deduct):					
Depreciation and amortization, including debt issuance cost amortization	(116,307)	(105,324)	(57,069)	(39,287)	(24,286)
Write-off of debt issuance costs			(5,078)	(10,761)	(8,480)
Non-cash income from unconsolidated subsidiary			43	532	312
Derivative valuation change	(5,163)	14,700	(14,667)	2,262	(11,191)
(Loss) gain on assets sales, net	133,284	(472)	(1,522)		1,254
Unit based compensation expenses	(6,008)	(4,306)	(15,534)	(2,906)	
Gain on insurance settlement		3,282			
Trade accounts receivable, accrued revenues and related party receivables	(10,727)	(18,648)	28,789	5,506	43,012
Other current assets	(10,471)	6,615	1,394	(104)	2,644
Trade accounts payable, accrued cost of gas and liquids, and related party payables	3,762	40,772	(30,089)	1,359	(52,651)
Other current liabilities	6,726	(12,749)	149	(3,640)	(2,075)
Proceeds from early termination of interest rate swap				(4,940)	
Amount of swap termination proceeds reclassified into earnings			1,078	3,862	
Other assets and liabilities	1,433	(3,840)	(554)	(3,283)	3,261
Net income (loss)	140,489	101,328	(13,531)	(7,244)	(10,860)
Add (deduct):					
Interest expense, net	77,996	63,243	52,016	37,182	17,880
Depreciation and amortization	109,893	102,566	55,074	39,654	23,171
Income tax (benefit) expense	(1,095)	(266)	931		
EBITDA	327,283	266,871	94,490	69,592	30,191
Add (deduct):					
Non-cash (gain) loss from derivatives	5,163	(14,708)	11,500	(6,158)	9,530
(Gain) loss on assets sales, net	(133,284)	472	1,522		
Income from unconsolidated subsidiary	(7,886)				
Partnership s ownership interest in HPC s adjusted EBITDA	11,398				
Loss on debt refinancing			21,200	10,761	8,480
Other expense, net	2,486	1,838	13,522	18,616	3,029
Adjusted EBITDA	$ 205,160	$ 254,473	$ 142,234	$ 92,811	$ 51,230
Reconciliation of "Adjusted total segment margin" to net income (loss)					
Net income (loss)	$ 140,489	$ 101,328	$ (13,531)	$ (7,244)	$ (10,860)
Add (deduct):					

Operation and maintenance	130,826	131,629	58,000	39,496	24,291
General and administrative	57,863	51,323	39,713	22,826	15,039
Loss (gain) on assets sales, net	(133,284)	472	1,522		
Management services termination fee		3,888		12,542	
Transaction expenses		1,620	420	2,041	
Depreciation and amortization	109,893	102,566	55,074	39,654	23,171
Income from unconsolidated subsidiary	(7,886)				
Interest expense, net	77,996	63,243	52,016	37,182	17,880
Loss on debt refinancing			21,200	10,761	8,480
Other income and deductions, net	15,132	(332)	(1,252)	(839)	(733)
Discontinued operations					(732)
Income tax (benefit) expense	(1,095)	(266)	931		
Total segment margin	389,934	455,471	214,093	156,419	76,536
Add (deduct):					
Non-cash (gain) loss from derivatives	(10,523)	(14,708)	11,500	(6,158)	9,530
Non-cash put option expiration			3,059	3,658	1,956
Adjusted total segment margin	$ 379,411	$ 440,763	$ 228,652	$ 153,919	$ 88,022

Table of Contents

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.

OVERVIEW. We are a growth-oriented publicly-traded Delaware limited partnership, formed in 2005, engaged in the gathering, processing, contract compression and transportation of natural gas and NGLs. We provide these services through systems located in Louisiana, Texas, Arkansas, Pennsylvania and the mid-continent region of the United States, which includes Kansas, Colorado, and Oklahoma.

OUR OPERATIONS. We divide our operations into four 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 43 percent interest in HPC which, through RIGS, delivers natural gas from northwest Louisiana to markets as well as downstream pipelines in northeast Louisiana through a 450 mile intrastate pipeline system;

Contract Compression: We provide turn-key natural gas compression services whereby we guarantee our customers 98 percent mechanical availability of our compression units for land installations and 96 percent mechanical availability for over-water installations; and

Corporate and Others: We own and operate an interstate pipeline that consists of 10 miles of pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana. This pipeline has a FERC certificated capacity of 150 MMcf/d.

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. 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. We regard the margin from this type of arrangement as an important analytical measure of these arrangements. 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.

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.

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 sell natural gas on intrastate and interstate pipelines to gas marketing companies, independent power producers, and utilities. 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 43 percent 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 revenue and segment margins principally under fee-based transportation contracts or through the purchases of natural gas at one of the inlets to the pipeline and the sales of natural gas at an outlet.

Table of Contents

The margin HPC 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, HPC s revenue from these arrangements would be reduced.

Generally, HPC, through RIGS, provides to shippers two types of fee-based transportation services:

- *Firm Transportation.* When RIG agrees to provide firm transportation service, it becomes obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on RIG s part, the shipper pays a specified reservation charge, whether or not it utilizes the capacity. In most cases, the shipper also pays a commodity charge with respect to quantities actually transported by RIGS.

- *Interruptible Transportation.* When RIG agrees to provide interruptible transportation service, it becomes obligated to transport natural gas nominated by the shipper only to the extent that it has available capacity. For this service, the shipper pays no reservation charge but pays a commodity charge for quantities actually shipped.

HPC, through RIGS, provides transportation services under the terms of its contracts and under an operating statement that RIG has filed with FERC with respect to transportation authorized under section 311 of the NGPA.

Contract Compression segment. We provide turn-key natural gas compression services whereby we guarantee our customers 98 percent mechanical availability of our compression units for land installations and 96 percent mechanical availability for over-water installations. We operate more than 753,000 horsepower of compression for third-party producers in Texas, Louisiana, Arkansas and Pennsylvania. In addition, our contract compression segment operates approximately 149,000 horsepower of compression for our gathering and processing segment and also operates approximately 29,000 horsepower of compression owned by RIG.

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 revenue minus cost of sales. We calculate our Gathering and Processing segment margin and Corporate and Others segment margin as our revenue 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 our contribution of RIGS to HPC, we calculated our Transportation segment margin as revenue generated by fee income as well as, in those instances in which we purchased and sold gas for our account, gas sales revenue minus the cost of natural gas that we purchased and transported. After our contribution of RIGS to HPC, 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 an unconsolidated subsidiary.

Table of Contents

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

We calculate total segment margin as the total of segment margin of our four segments, less the intersegment elimination.

Adjusted Segment Margin and Adjusted Total Segment Margin. We define adjusted segment margin for our Gathering and Processing segment as gathering and processing segment margin adjusted for non-cash gains (losses) from derivatives. We define adjusted segment margin for our Transportation segment as Transportation segment margin adjusted for non-cash gains (losses) from derivatives. Adjusted segment margin is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product purchases and sales, a key component of our operations.

We define adjusted total segment margin as total segment margin adjusted for non-cash gains (losses) from derivatives. Our adjusted total segment margin equals the sum of our operating segments adjusted segment margins or segment margins, including intersegment eliminations.

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 revenue 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 plus interest expense, provision for income taxes and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus non-cash loss (gain) from derivative activities, loss (gain) on asset sales, net, loss on debt refinancing, other (income) expense, net, and the Partnership s interest in adjusted EBITDA from unconsolidated subsidiaries less income from unconsolidated subsidiary. 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. See Item 6 Selected Financial Data for a reconciliation of EBITDA and adjusted EBITDA to net cash flows provided by (used in) operating activities and to net income (loss).

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. At December 31, 2009, the number of working natural gas drilling rigs in the United States totaled 759 compared to 665 in mid July of 2009, a 14 percent increase. EIA expects a 3 percent decline in natural gas production in 2010 due to the natural decline in existing well production and the lagged effect of reduced drilling. EIA also expects production to increase by 1.3 percent in 2011. Demand for natural gas in 2010 is expected to remain unchanged. EIA expects that higher prices for natural gas in 2010 will decrease the consumption in the electric power section by 2.8 percent; this decline is expected to be offset by growth in the residential, commercial and industrial sectors. Natural gas consumption in 2011 is expected to increase by 0.4 percent, led by a 2.5 percent increase in consumption in the industrial sector. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

EIA forecasts demand for crude oil and NGLs to increase in 2010 and 2011. Total petroleum consumption is forecasted to increase by 1.1 percent in 2010 with all of the major components contributing to this increase.

Fluctuations in energy prices can affect production rates over time and levels of investment by third parties in exploration for and development of new natural gas reserves. We have no control over the level of natural gas exploration and development activity in the areas of our operations.

Outlook. Global financial markets and economic conditions have been, and continue to be, volatile. The cost of raising money from the credit market generally has increased. As we expect to continue to incur substantial capital expenditures and working capital needs, we may experience difficulty in accessing the capital markets.

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 revenue 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.

HISTORY OF THE PARTNERSHIP

Initial Public Offering. Prior to the closing of our initial public offering on February 3, 2006, Regency Gas Services LLC was converted into a limited partnership named Regency Gas Services LP, and was contributed to us by Regency Acquisition LP, a limited partnership indirectly owned by the HM Capital Investors.

Enbridge Asset Acquisition. TexStar acquired two sulfur recovery plants, one NGL plant and 758 miles of pipelines in east and south Texas from subsidiaries of Enbridge for $108,282,000 inclusive of transaction expenses on December 7, 2005. The Enbridge acquisition was accounted for using the purchase method of accounting. The results of operations of the Enbridge assets are included in our statements of operations beginning December 1, 2005.

Acquisition of TexStar. On August 15, 2006, we acquired all the outstanding equity of TexStar for $348,909,000, which consisted of $62,074,000 in cash, the issuance of 5,173,189 Class B common units valued at $119,183,000 to an affiliate of HM Capital, and the assumption of $167,652,000 of TexStar s outstanding bank debt. Because the TexStar acquisition was a transaction between commonly controlled entities, we accounted for the TexStar acquisition in a manner similar to a pooling of interests. As a result, our historical financial statements and the historical financial statements of TexStar have been combined to reflect the historical operations, financial position and cash flows for periods in which common control existed, December 1, 2004 forward.

Table of Contents

Pueblo Acquisition. On April 2, 2007, we acquired a 75 MMcf/d gas processing and treating facility, 33 miles of gathering pipelines and approximately 6,000 horsepower of compression. The purchase price for the Pueblo acquisition consisted of (1) the issuance of 751,597 common units, valued at $19,724,000 and (2) the payment of $34,855,000 in cash, exclusive of outstanding Pueblo liabilities of $9,822,000 and certain working capital amounts acquired of $108,000. The Pueblo acquisition was accounted for using the purchase method of accounting. The results of operations of the Pueblo assets are included in our statements of operations beginning April 1, 2007.

GE EFS acquisition of HM Capital s Interest. On June 18, 2007, indirect subsidiaries of GECC acquired 91.3 percent of both the member interest in the General Partner and the outstanding limited partner interests in the General Partner from an affiliate of HM Capital Partners and acquired 17,763,809 of the outstanding subordinated units, exclusive of 1,222,717 subordinated units which were owned directly or indirectly by certain members of the Partnership s management team. The Partnership was not required to record any adjustments to reflect the acquisition of the HM Capital Partners interest in the Partnership or the related transactions.

Acquisition of FrontStreet. On January 7, 2008, we acquired all of the outstanding equity and minority interest (the FrontStreet Acquisition) of FrontStreet from ASC, an affiliate of GECC, and EnergyOne. 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. We financed the cash portion of the purchase price with borrowings under our revolving credit facility.

Because the acquisition of ASC s 95 percent interest is 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 we applied the purchase method of accounting.

Acquisition of CDM. On January 15, 2008, we and an indirect wholly owned subsidiary consummated an agreement and plan of merger with CDM Resource Management, Ltd. The total purchase price consisted of (a) the issuance of an aggregate of 7,276,506 Class D common units, which were valued at $219,590,000 and (b) an aggregate of $478,445,000 in cash, $316,500,000 of which was used to retire CDM s debt obligations. The results of operations of CDM are included in our statements of operations beginning January 16, 2008.

Acquisition of Nexus. On March 25, 2008, we acquired Nexus by merger for $88,640,000 in cash, including customary closing adjustments. The results of operations of Nexus are included in our statements of operations beginning March 26, 2008.

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 interest in HPC. On September 2, 2009, we purchased an additional five percent interest from EFS Haynesville for $63,000,000, increasing the Partnership s ownership percentage from 38 percent to 43 percent.

Table of Contents

RESULTS OF OPERATIONS

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

	Year Ended December 31, 2009	2008	Change	Percent
	(in thousands except percentages and volume data)			
Total revenues	$ 1,089,497	$ 1,863,804	$ (774,307)	42%
Cost of sales	699,563	1,408,333	(708,770)	50
Total segment margin(1)	389,934	455,471	(65,537)	14
Operation and maintenance	130,826	131,629	(803)	1
General and administrative	57,863	51,323	6,540	13
(Gain) loss on asset sales, net	(133,284)	472	(133,756)	28,338
Management services termination fee		3,888	(3,888)	N/M
Transaction expenses		1,620	(1,620)	N/M
Depreciation and amortization	109,893	102,566	7,327	7
Operating income	224,636	163,973	60,663	37
Income from unconsolidated subsidiary	7,886		7,886	N/M
Interest expense, net	(77,996)	(63,243)	(14,753)	23
Other income and deductions, net	(15,132)	332	(15,464)	4,658
Income before income taxes	139,394	101,062	38,332	38
Income tax benefit	(1,095)	(266)	(829)	312
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%
Total segment margin(1)	$ 389,934	$ 455,471	$ (65,537)	14%
Add (deduct):				
Non-cash gain from derivatives	(10,523)	(14,708)	4,185	28
Adjusted total segment margin	379,411	440,763	(61,352)	14
Transportation segment margin	11,714	66,888	(55,174)	82
Contract compression segment margin	141,028	125,503	15,525	12
Corporate and others segment margin	11,284	3,248	8,036	247
Inter-segment eliminations	(4,604)	(4,573)	(31)	1
Adjusted gathering and processing segment margin	$ 219,989	$ 249,697	$ (29,708)	12%
System inlet volumes (MMBtu/d)(2)	1,538,750	1,522,431	16,319	1%

(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) System inlet volumes include total volumes taken into our gathering and processing and transportation systems.

N/M Not meaningful.

51

Table of Contents

The table below contains key segment performance indicators related to our discussion of our results of operations.

	Year Ended December 31, 2009	2008	Change	Percent
	(in thousands except percentages and volume data)			
Gathering and Processing Segment				
Financial data:				
Adjusted segment margin[1]	$ 219,989	$ 249,697	$ (29,708)	12%
Operation and maintenance[2]	88,520	82,689	5,831	7
Operating data:				
Throughput (MMBtu/d)[3]	1,000,621	1,025,779	(25,158)	2
NGL gross production (Bbls/d)	24,024	22,390	1,634	7
Transportation Segment				
Financial data:				
Segment margin[1]	$ 11,714	$ 66,888	$ (55,174)	82%
Operation and maintenance[2]	2,112	3,540	(1,428)	40
Operating data:				
Throughput (MMBtu/d)[3]	169,143	770,939	(601,796)	78
Contract Compression				
Financial data:				
Segment margin[1]	$ 141,028	$ 125,503	$ 15,525	12%
Operation and maintenance[2]	45,744	49,799	(4,055)	8
Operating data:				
Revenue generating horsepower[4]	753,328	778,667	(25,339)	3%
Average horsepower per revenue generating compression unit	849	856	(7)	1
Corporate and Others				
Financial data:				
Segment margin[1]	$ 11,284	$ 3,248	$ 8,036	247%
Operation and maintenance[2]	426	74	352	476

(1) Combined adjusted segment margin for our segments differs from consolidated total adjusted segment margin due to intersegment eliminations.

(2) Combined operation and maintenance expense varies from consolidated operation and maintenance expense due to intersegment eliminations.

(3) Combined throughput volumes for the gathering and processing and transportation segments vary from consolidated system inlet volumes due to intersegment eliminations.

(4) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.

Table of Contents

The following tables set forth certain information regarding contract compression s revenue generating horsepower as of December 31, 2009 and 2008.

	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.

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 $65,537,000 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 $15,464,000 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 $14,753,000 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;
- an increase in depreciation and amortization expense of $7,327,000 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 $379,411,000 in the year ended December 31, 2009 from $440,763,000 in the year ended December 31, 2008. This decrease was attributable to a decrease of $29,708,000 in the adjusted gathering and processing segment margin, and a decrease of $55,174,000 in transportation segment margin related to the contribution of RIG to HPC, which was offset by the addition of $15,525,000 in contract compression segment margin, and the addition of $8,036,000 in corporate and others segment margin.

Adjusted gathering and processing segment margin decreased to $219,989,000 for the year ended December 31, 2009 from $249,697,000 for the year ended December 31, 2008. The major components of this decrease were as follows:

$24,066,000 related to lower commodity prices compared to the 2008 price levels; and

$5,642,000 from various other sources primarily related to our producer services function.

Table of Contents

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.

Corporate and others segment margin increased to $11,284,000 in the year ended December 31, 2009 from $3,248,000 in 2008. The increase is attributable to the following:

- $4,726,000 in reimbursement of management fees from HPC for general and administrative expenses;
- $2,576,000 additional segment margin generated from increased volumes in 2009 for a regulated entity; and
- $734,000 from various other sources primarily related to our interstate pipeline.

Operation and Maintenance. Operation and maintenance expense remained relatively consistent with the year ended December 31, 2008, declining $803,000 in 2009, a one percent decrease. The changes in operations and maintenance expense for the year are the result of the following factors:

- $6,628,000 decrease related to the contribution of RIG to HPC;
- $1,630,000 decrease in materials and parts costs as a result of cost control measures; and were offset by
- $7,317,000 increase in compression operation and maintenance expense in the gathering and processing segment due to the increased focus on maintenance of our compression fleet; and
- $138,000 increase in various other operation and maintenance expenses.

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, a 13 percent increase. 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 Sale of Asset, net. Gain on sale of asset, 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 $109,893,000 in the year ended December 31, 2009 from $102,566,000 in the year ended December 31, 2008, a seven percent increase. The increase was primarily due to:

$18,977,000 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 $77,996,000 in the year ended December 31, 2009 from $63,243,000 in 2008. This increase was primarily attributable to the issuance of $250,000,000 of 9.375 percent senior notes in May 2009.

Table of Contents

Other Income and Deductions, net. Other income and deductions, net increased $15,464,000 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.

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

The table below contains key company-wide performance indicators related to our discussion of the results of operations.

	Year Ended December 31,			
	2008	2007	Change	Percent
	(in thousands except percentages and volume data)			
Total revenues	$ 1,863,804	$ 1,190,238	$ 673,566	57%
Cost of sales	1,408,333	976,145	432,188	44
Total segment margin[1]	455,471	214,093	241,378	113
Operation and maintenance	131,629	58,000	73,629	127
General and administrative	51,323	39,713	11,610	29
Loss on asset sales, net	472	1,522	(1,050)	69
Management services termination fee	3,888		3,888	N/M
Transaction expenses	1,620	420	1,200	286
Depreciation and amortization	102,566	55,074	47,492	86
Operating income	163,973	59,364	104,609	176
Interest expense, net	(63,243)	(52,016)	(11,227)	22
Loss on debt refinancing		(21,200)	21,200	N/M
Other income and deductions, net	332	1,252	(920)	73
Income (loss) before income taxes	101,062	(12,600)	113,662	902
Income tax (benefit) expense	(266)	931	(1,197)	129
Net income (loss)	101,328	(13,531)	114,859	849
Net income attributable to the noncontrolling interest	(312)	(305)	(7)	2
Net income (loss) attributable to Regency Energy Partners LP	$ 101,016	$ (13,836)	$ 114,852	830%
Total segment margin[1]	$ 455,471	$ 214,093	$ 241,378	113%
Add (deduct):				
Non-cash (gain) loss from derivatives	(14,708)	11,500	(26,208)	228
Non-cash put option expiration		3,059	(3,059)	N/M
Adjusted total segment margin	440,763	228,652	212,111	93
Transportation segment margin	66,888	52,548	14,340	27
Non-cash gain from derivatives		(390)	390	N/M
Adjusted transportation segment margin	66,888	52,158	14,730	28
Contract compression segment margin	125,503		125,503	N/M
Corporate and other segment margin	3,248	2,362	886	38
Inter-segment elimination	(4,573)		(4,573)	N/M
Adjusted gathering and processing segment margin	$ 249,697	$ 174,132	$ 75,565	43%
System inlet volumes (MMBtu/d)[2]	1,522,431	1,225,918	296,513	24%

(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) System inlet volumes include total volumes taken into our gathering and processing and transportation systems.

N/M Not meaningful.

Table of Contents

The table below contains key segment performance indicators related to our discussion of our results of operations.

	Year Ended December 31,			
	2008	2007	Change	Percent
	(in thousands except percentages and volume data)			
Gathering and Processing Segment				
Financial data:				
Adjusted segment margin(1)	$ 249,697	$ 174,132	$ 75,565	43%
Operation and maintenance(2)	82,689	53,496	29,193	55
Operating data:				
Throughput (MMBtu/d)(3)	1,025,779	772,930	252,849	33
NGL gross production (Bbls/d)	22,390	21,808	582	3
Transportation Segment				
Financial data:				
Adjusted segment margin(1)	$ 66,888	$ 52,158	$ 14,730	28%
Operation and maintenance(2)	3,540	4,407	(867)	20
Operating data:				
Throughput (MMBtu/d)(3)	770,939	751,761	19,178	3
Contract Compression				
Financial data:				
Segment margin(1)	$ 125,503	N/A	N/A	N/A
Operation and maintenance(2)	49,799	N/A	N/A	N/A
Operating data:				
Revenue generating horsepower(4)	778,667	N/A	N/A	N/A
Average horsepower per revenue generating compression unit	856	N/A	N/A	N/A
Corporate and Others				
Financial data:				
Segment margin(1)	$ 3,248	$ 2,362	$ 886	38%
Operation and maintenance(2)	74	97	(23)	24

(1) Combined adjusted segment margin for our segments differs from consolidated total adjusted segment margin due to inter-segment eliminations.

(2) Combined operation and maintenance expense for our segments differs from consolidated operation and maintenance expense due to inter-segment eliminations.

(3) Combined throughput volumes for the gathering and processing and transportation segment vary from consolidated system inlet volumes due to inter-segment eliminations.

(4) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.

N/A Not applicable as we acquired the contract compression segment in January 2008.

Net Income (Loss) Attributable to Regency Energy Partners LP. Net income attributable to Regency Energy Partners LP for the year ended December 31, 2008 increased $114,852,000, compared with the year ended December 31, 2007. The increase in net income attributable to the Partnership was primarily attributable to an increase in total segment margin of $241,378,000 and the absence in the current period of a $21,200,000 loss on debt refinancing related to the termination penalty associated with the redemption of 35 percent of our senior notes. The increase in total segment margin was primarily due to the acquisition of our contract compression, FrontStreet, and Nexus assets and organic growth in the gathering and processing segment. We were required to use the as-if pooling method of accounting for our FrontStreet acquisition because it involved entities under common control. Common control began on June 18, 2007, therefore the discussion below includes activity from FrontStreet from June 18, 2007 forward even though the acquisition occurred in January 2008. Partially offsetting these increases in net income attributable to the Partnership were:

- an increase in operation and maintenance expense of $73,629,000 primarily due to our contract compression and FrontStreet assets acquired in January 2008 and increases in organic growth-related maintenance and employee-related expenses mainly in the gathering and processing segment;

- an increase in depreciation and amortization expense of $47,492,000 primarily due to the acquisition of our contract compression, FrontStreet, and Nexus assets and organic growth projects primarily in the gathering and processing segment;

- A net increase in general and administrative expenses of $11,610,000 primarily due to our contract compression acquisition in January 2008 and increased employee-related expenses, which was reduced by the absence of an $11,928,000 expense associated with the vesting of all outstanding LTIP grants incurred in 2007 when GE EFS acquired our general partner;

- an increase in interest expense of $11,227,000 primarily due to increased levels of borrowings; and

- a payment of a management contract services termination fee of $3,888,000 in 2008 related to the acquisition of FrontStreet.

Adjusted Total Segment Margin. Adjusted total segment margin for the year ended December 31, 2008 increased by $212,111,000 compared with the year ended December 31, 2007. This increase was attributable to an increase of $75,565,000 in adjusted gathering and processing segment margin, an increase of $14,730,000 in adjusted transportation segment margin, an increase of $886,000 in corporate and others, and the addition of $125,503,000 in contract compression segment margin.

Adjusted gathering and processing segment margin increased to $249,697,000 for the year ended December 31, 2008 from $174,132,000 for the year ended December 31, 2007. The major components of this increase were as follows:

- $25,274,000 from a full year s operation of our FrontStreet assets which were consolidated on June 18, 2007;

- $19,200,000 from increased throughput and organic growth in south Texas;

- $11,770,000 from increased throughput and organic growth in north Louisiana;

- $9,548,000 from increased sulfur prices;

- $7,589,000 from the operations of our Nexus assets acquired in January 2008; and

- $4,705,000 in increased margins associated with our producer services function.

Adjusted transportation segment margin increased to $66,888,000 for the year ended December 31, 2008 from $52,158,000 for the year ended December 31, 2007. The major components of this increase were as follows:

- $12,440,000 from increased operational efficiencies coupled with increased commodity prices; and

- $1,684,000 from increased throughput volumes and changes in contract mix.

Contract compression segment margin was $125,503,000 in the year ended December 31, 2008, which consisted of $137,122,000 of operating revenue and $11,619,000 of direct operating cost.

Table of Contents

Operation and Maintenance. Operations and maintenance expense increased to $131,629,000 in the year ended December 31, 2008 from $58,000,000 for the corresponding period in 2007, a 127 percent increase. This increase is primarily the result of the following factors:

- $45,326,000 related to our contract compression assets acquired in January 2008, net of intercompany eliminations;
- $14,972,000 related to our FrontStreet assets, which are operated by a third party;
- $8,864,000 related primarily to the gathering and processing segment associated with organic growth projects since December 31, 2007 involving compressor and other maintenance expenses in 2008;
- $2,726,000 increase in employee-related expenses primarily related to increases in annual salaries, bonus accrual and employer benefit payments mostly in the gathering and processing segment;
- $1,316,000 increase in utility expense due to higher commodity prices primarily in the gathering and processing segment;
- $1,227,000 increase in contractor expense in the transportation segment due to compressor maintenance; and
- partially offset by a $1,393,000 increase in insurance proceeds received in August 2008 ($3,134,000) versus November 2007 ($1,741,000) related to a March 2007 compressor fire in the transportation segment.

General and Administrative. General and administrative expense increased to $51,323,000 in the year ended December 31, 2008 from $39,713,000 for the same period in 2007, a 29 percent increase. In June 2007, the Partnership incurred a one-time charge of $11,928,000 associated with the vesting of all outstanding common unit options upon a change in control of our general partner. Absent this expense, general and administrative expenses increased by $23,538,000 primarily due to:

- $16,224,000 related to our contract compression acquisition in January 2008;
- $5,788,000 increase in employee-related expenses primarily due to hiring of new employees, employer benefit payments and bonus accruals; and
- $958,000 increase in legal expenses.

Management Services Termination Fee. In 2008, we recorded $3,888,000 for the termination of a long-term management services contract associated with our FrontStreet acquisition.

Depreciation and Amortization. Depreciation and amortization expense increased to $102,566,000 in the year ended December 31, 2008 from $55,074,000 for the year ended December 31, 2007, an 86 percent increase. The increase was primarily due to:

- $28,448,000 related to our contract compression assets acquired in January 2008;

- $8,440,000 related to our FrontStreet assets which for the year ended December 31, 2008 are being depreciated over a shorter useful life as compared to 2007 and the year ended December 31, 2008 includes a full year where as the year ended December 31, 2007 only included six months of depreciation;

- $7,428,000 related to various organic growth projects completed since December 31, 2007, primarily in the gathering and processing segment; and

- $3,176,000 related to our Nexus assets acquired in March 2008.

Interest Expense, Net. Interest expense, net increased $11,227,000, or 22 percent, in 2008 compared to 2007. Of this increase, $26,266,000 was attributable to increased levels of borrowings partially offset by $15,039,000 primarily attributable to lower interest rates.

Table of Contents

Loss on Debt Refinancing. In the year ended December 31, 2007, we paid a $16,122,000 early repayment penalty associated with the redemption of 35 percent of our senior notes. We also expensed $5,078,000 of debt issuance costs related to the pay off of the term loan facility and the early termination of senior notes. No similar transactions occurred in 2008.

Results of Operation for HPC

Although we own a 43 percent 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 to compare to RIG s results of operations for the year ended December 31, 2008. For the years ended December 31, 2008 and 2007 the results of operations only relate to RIG.

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%
System inlet volumes (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

Table of Contents

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 by EFS Haynesville and Alinda Investors; and were partially offset by
- 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.

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

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

	Year Ended December 31,			
	2008	2007	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 68,921	$ 55,207	$ 13,714	25%
Cost of sales	2,033	2,659	(626)	24
Segment margin	66,888	52,548	14,340	27
Operation and maintenance	3,540	4,407	(867)	20
General and administrative	9		9	N/M
Loss on asset sales, net	44	9	35	389
Depreciation and amortization	14,099	13,457	642	5
Operating income	49,196	34,675	14,521	42
Other income and deductions, net	11	24	(13)	54
Net income	$ 49,207	$ 34,699	$ 14,508	42%
System inlet volumes (MMbtu/d)	770,939	751,761	19,178	3%

N/M Not meaningful

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

	Year Ended December 31, 2008	2007
	(in thousands)	
Net income	$ 49,207	$ 34,699
Add (deduct):		
Operation and maintenance	3,540	4,407
General and administrative	9	
Loss on asset sales, net	44	9
Depreciation and amortization	14,099	13,457
Other income and deductions, net	(11)	(24)
Segment margin	$ 66,888	$ 52,548
Add (deduct):		
Non-cash gain from derivatives		(390)
Adjusted segment margin	$ 66,888	$ 52,158

Net income increased to $49,207,000 in the year ended December 31, 2008 from $34,699,000 in the year ended December 31, 2007. The increase in net income was primarily attributable to the increase in segment margin of $14,340,000 primarily due to the increase in natural gas prices and volumes in 2008 compared to those in 2007.

HPC s adjusted EBITDA for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Year Ended December 31, 2009	2008	2007
		(in thousands)	
Net income	$ 26,867	$ 49,207	$ 34,699
Add (deduct):			
Depreciation and amortization	10,962	14,099	13,457
Interest expense	158		
EBITDA	$ 37,987	$ 63,306	$ 48,156
Add (deduct):			
Non-cash gain from derivatives			(390)
Loss on assets sales		44	9
Gain on insurance settlement		(3,134)	(1,741)
Other expense, net	50	33	
Adjusted EBITDA	$ 38,037	$ 60,249	$ 46,034

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.

Cash Distributions. On January 7, 2010 the HPC management committee paid a distribution of $8,200,000, of which the Partnership received its pro-rata share of $3,526,000.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

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

Table of Contents

- operating lease facilities;
- asset sales;
- debt offerings; and
- issuance of additional partnership units.

We expect our growth capital expenditures to be approximately $167,000,000 in 2010, inclusive of our 43 percent of the growth capital expenditures related to HPC. Our anticipated 2010 organic growth capital expenditures include $137,000,000 for the expansion of our gathering and processing facilities, $14,000,000 for additional compression for our contract compression segment, and $8,000,000 related to the corporate and others segment. We expect growth capital expenditures related to HPC for 2010 to be approximately $8,000,000 which represents our proportionate share. In total, $77,000,000 of the $167,000,000 relates to the previously approved projects related to expansions in the Haynesville Shale in the Gathering and Processing and Transportation segments.

Although we intend to move forward with our planned internal growth projects, we may further revise the timing and scope of these projects as necessary to adapt to existing economic conditions and the benefits expected to accrue to our unitholders from our expansion activities may be reduced by substantial cost of capital increases during this period.

Working Capital 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 segment records deferred revenue as a current liability. The deferred revenue represent billings in advance of services performed. As the revenues associated with the deferred revenue are earned, the liability is reduced.

Our working capital surplus decreased to $17,468,000 at December 31, 2009 from $19,453,000 at December 31, 2008. This decrease was primarily due to the following factors:

- a net decrease in the market value of derivative assets and liabilities of $18,571,000 due to an increase in commodity prices compared to 2008 price levels and more favorable pricing for new contracts;
- a decrease in other current assets of $2,782,000 primarily attributable to a decrease in other prepaid assets;
- an increase in other current liabilities of $1,794,000 which relate primarily to the interest accrual for our senior notes; and were offset by;
- a net increase in trade accounts receivable, accrued revenues, related party receivables, trade accounts payable, accrued cost of gas and liquids, deferred revenue and related party payables of $11,934,000 primarily due to the timing of cash receipts and payments; and
- a $9,228,000 increase in cash and cash equivalents.

Cash Flows from Operating Activities. 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.

Net cash flows provided by operating activities increased to $181,298,000 in the year ended December 31, 2008 from $79,529,000 in the year ended December 31, 2007. Cash generated from operations increased primarily due to increased total segment margin of $241,378,000, primarily due to the operating activity of our contract compression, FrontStreet and Nexus assets acquired in the first calendar quarter of 2008 and organic growth in the gathering and processing segment.

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 credit facility.

Cash Flows from Investing Activities. 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 the Haynesville Expansion Project, in 2009.

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 or to maintain existing system volumes and related cash flows. In the year ended December 31, 2009, we incurred $136,260,000 of growth capital expenditures. Growth capital expenditures for the year ended December 31, 2009 primarily related to $87,191,000 for the fabrication of new compressor packages for our contract compression segment and $49,069,000 for organic growth projects in our gathering and processing segment. In addition, we incurred $13,700,000 related to our 43 percent of the growth capital expenditures related to HPC.

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, 2009, we incurred $20,170,000 of maintenance capital expenditures.

Net cash flows used in investing activities increased to $948,629,000 in the year ended December 31, 2008 from $157,933,000 in the year ended December 31, 2007. The increase is primarily due to cash consideration paid for the contract compression, FrontStreet, and Nexus assets in the first calendar quarter of 2008 and to organic growth in the gathering and processing segment.

Cash Flows from Financing Activities. 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 resulted from an acquisition of assets 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.

Net cash flows provided by financing activities increased to $734,959,000 in the year ended December 31, 2008 from $99,443,000 in the year ended December 31, 2007 primarily due to the following:

- an increase in net borrowings under our revolving credit facility of $585,429,000 due to increased borrowings associated with organic growth primarily in the gathering and processing segment and our contract compression, FrontStreet, and Nexus acquisitions;

the absence in 2008 of the 35 percent redemption of our senior notes in 2007 of $192,500,000; and partially offset by

a decrease in proceeds from equity issuances of $154,231,000.

Table of Contents

Capital Resources

Description of Our Indebtedness. As of December 31, 2009, our aggregate outstanding indebtedness totaled $1,014,299,000 and consisted of $419,642,000 in borrowings under our credit facility and $594,657,000 of outstanding senior notes as compared to our aggregate outstanding indebtedness as of December 31, 2008, which totaled $1,126,229,000 and consisted of $768,729,000 in borrowings under our credit facility and $357,500,000 of outstanding senior notes.

Credit Ratings. Our credit ratings as of February 23, 2010 are provided below.

	Moody's	Standard & Poor's
Regency Energy Partners LP		
Outlook	Stable	Stable
Senior notes due 2013	B1	B
Senior notes due 2016	B1	B
Corporate rating/total debt	Ba3	BB-

Senior Notes due 2016. In May 2009, we issued $250,000,000 senior notes in a private placement that mature on June 1, 2016. The senior notes bear interest at 9.375 percent with interest payable semi-annually in arrears on June 1 and December 1. We paid a $13,760,000 discount upon issuance. The net proceeds were used to partially repay revolving loans under our 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, we may redeem all or part of these notes for the principal amount plus a declining premium until June 1, 2015, and thereafter at par, plus accrued and unpaid interest. At any time prior to June 1, 2013, we 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, each noteholder of senior notes due 2016 will be entitled to require us 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 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, we will no longer be subject to many of the foregoing covenants. At December 31, 2009, we were in compliance with these covenants.

Senior Notes due 2013. In 2006, we issued $550,000,000 senior notes that mature on December 15, 2013 in a private placement. The senior notes bear interest at 8.375 percent and interest is payable semi-annually in

Table of Contents

arrears on each June 15 and December 15. In August 2007, we exercised our option to redeem 35 percent or $192,500,000 of these senior notes at a price of 108.375 percent of the principal amount plus accrued interest. Accordingly, we recorded a redemption premium of $16,122,000 and a loss on debt refinancing and unamortized loan origination costs of $4,575,000 were charged to loss on debt refinancing in the year ended December 31, 2007. Under the senior notes terms, no further redemptions are permitted until December 15, 2010.

We may redeem the outstanding senior notes, in whole or in part, at any time on or after December 15, 2010, at a redemption price equal to 100 percent of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest and liquidated damages, if any, to the redemption date.

Upon a change of control, each noteholder of senior notes due 2013 will be entitled to require us 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 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, we will no longer be subject to many of the foregoing covenants. At December 31, 2009, we were in compliance with these covenants.

Fourth Amended and Restated Credit Agreement. In February 2008, RGS Fourth Amended and Restated Credit Agreement (Credit Facility) was expanded to $900,000,000 and the availability for letters of credit was increased to $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 credit facility have been met. The maturity date of the credit facility is August 15, 2011.

Effective March 17, 2009, RGS amended the Credit Facility to authorize the contribution of RIG to the joint venture (HPC) and allow for a future investment of up to $135,000,000 in HPC. The amendment imposed additional financial restrictions that limit the ratio of senior secured indebtedness to adjusted EBITDA. 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 1.50 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 0.500 percent. On July 24, 2009, RGS further amended its Credit Facility to allow for a $25,000,000 working capital facility for RIG. These amendments did not materially change other terms of the RGS revolving credit facility.

On September 15, 2008, Lehman filed a petition in the United States Bankruptcy Court seeking relief under Chapter 11 of the United States Bankruptcy Code. As a result, a subsidiary of Lehman that is a committed lender under our Credit Facility has declined requests to honor its commitment to lend. The total amount committed by Lehman was $20,000,000 and as of December 31, 2009, we had borrowed all but $10,675,000 that amount. Since

Table of Contents

Lehman has declined requests to honor its remaining commitment, our total size of the Credit Facility s capacity has been reduced from $900,000,000 to $889,325,000. Further, if we make repayments of loans against the Credit Facility which were, in part, funded by Lehman, the amounts funded by Lehman may not be reborrowed.

RGS must pay (i) a commitment fee equal to 0.5 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 3.0 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 Credit Facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to adjusted EBITDA and adjusted EBITDA to interest expense within certain threshold ratios. At December 31, 2009 and 2008, RGS and its subsidiaries were in compliance with these covenants.

The Credit Facility restricts the ability of RGS to pay dividends and distributions other than reimbursements to us for expenses and payment of dividends to us to the extent of our determination of available cash (so long as no default or event of default has occurred or is continuing). The Credit Facility also contains various covenants that limit (subject to certain exceptions and negotiated baskets), 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 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 Credit Facility or reasonable extensions thereof.

Letters of Credit. At December 31, 2009, we had outstanding letters of credit totaling $16,257,000 under our Credit Facility. The total fees for letters of credit accrue at an annual rate of 3.125 percent, which is applied to the daily amount of letters of credit exposure.

HPC Working Capital Facility. On July 27, 2009, RIG entered into a $25,000,000 revolving credit facility that expires on July 27, 2012. We believe RIG s working capital facility will reduce the likelihood of us having to fund 43 percent of HPC s working capital needs in the future.

Equity offerings. On September 2, 2009, we 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. The Series A Preferred Units are convertible to common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions. The proceeds from the equity issuance were used to acquire a five percent interest in HPC from EFS Haynesville and to repay a portion of the credit facility.

On December 2, 2009 we issued 12,075,000 common units at $19.12 per unit. We received $220,318,000 in net proceeds exclusive of the general partner s proportionate capital contribution of $4,712,000. The proceeds from the equity issuance were used to repay a portion of our credit facility borrowings.

Table of Contents

Total Contractual Cash Obligations. The following table summarizes our total contractual cash obligations as of December 31, 2009.

Operating Lease Facility. The $75,000,000 operating lease facility with Caterpillar Financial Services Corporation expired on December 31, 2009. We utilized $9,621,000 of the operating lease facility during the year ended December 31, 2009.

			Payment Period		
Contractual Cash Obligations	**Total**	**2010**	**2011-2012**	**2013-2014**	**Thereafter**
			(in thousands)		
Long-term debt (including interest)[1]	$ 1,330,330	$ 72,505	$ 538,353	$ 434,316	$ 285,156
Capital leases	9,458	589	858	910	7,101
Operating leases	26,105	3,838	7,227	5,065	9,975
Purchase obligations	3,236	3,236			
Distributions and Redemption of Series A Preferred Units[2]	235,629	5,836	15,563	15,563	198,667
Total[3][4]	$ 1,604,758	$ 86,004	$ 562,001	$ 455,854	$ 500,899

(1) Assumes a constant LIBOR interest rate of 0.99 plus applicable margin (3.0 percent as of December 31, 2009) for our revolving credit facility. The principal of our outstanding senior notes ($607,500,000) bears a weighted average fixed rate of 8.787 percent.

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

(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) Excludes deferred tax liabilities of $6,996,000 as the amount payable by period can not be readily estimated in light of net operating loss carryforwards and future business plans for the entity that generates the deferred tax liability.

OTHER MATTERS

Legal. The Partnership is involved in various claims and lawsuits 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.

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

IRS Audits. The IRS mailed two 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 (collectively, the NBAPs). The Partnership understands this to be a routine audit of various items of partnership income, gain, deductions, losses and credits. The audit is in its preliminary stages so it is not known whether the IRS will propose any adjustments to the Partnership s tax returns, whether such adjustments would be material, or how such adjustments would affect unitholders. We are making this disclosure, on behalf of our tax matters partner, to satisfy the IRS requirement that we provide a copy of the NBAPs to certain of our partners. Copies of the NBAPs 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.

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.

Table of Contents

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 liquids 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 as 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 contracts, customer relations, trade names, and licenses and permits. We value customer contracts using a discounted cash flow model. 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. For licenses and permits, we make assumptions regarding the period of time it would take to replace them, using a lost profits model to estimate a fair value. We determine 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 assigned to the tangible assets and separately recognized intangible assets acquired less liabilities assumed of 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 services, commodity prices, and operating costs are considered as a component of the calculation of future discounted cash flows. Further, the discount rate requires estimations 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 the Partnership s interest in investments of greater than 20 percent voting stock or exerts significant influence over an investee and where the Partnership lacks control over the investee.

Depreciation Expense, Cost Capitalization and Impairment. Our assets consist primarily of natural gas gathering pipelines, processing plants, transmission pipelines, 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 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.

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 document) or market condition awards (also defined as performance-based awards in the LTIP plan document). 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, a Monte Carlo simulation was performed which 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. On January 1, 2008, we adopted the fair value measurement provisions for financial assets and liabilities and on January 1, 2009, we applied the fair value measurement provisions to non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. These 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.

Table of Contents

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, dividend 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 NGL, 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 uncertainty. Our profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect our ability to make distributions to our unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, we may not be able to match pricing terms or to cover our risk to price exposure with financial hedges, and we may be exposed to commodity price risk. It is our policy not to take any speculative positions with derivative contracts.

We have executed swap contracts settled 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, 2009		As of January 15, 2010	
	2010	2011	2010	2011
NGLs	80%	33%	80%	33%
Condensate	84%	21%	84%	42%
Natural gas	85%	27%	85%	27%

Table of Contents

The following table sets forth certain information regarding our natural gas, NGLs, WTI, and interest rate swaps outstanding at December 31, 2009. The relevant index price that we pay is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas, as reported by the Oil Price Information Service (OPIS). The relevant index price for natural gas is NYMEX on the pricing dates as defined by the swap contracts. The relevant index for WTI is the monthly average of the daily price of WTI as reported by the NYMEX.

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive Weighted Average Price		Fair Value Asset/(Liability) (in thousands)
January 2010-September 2011	Ethane	808	(MBbls)	Index	$0.52	($/gallon)	$ (5,177)
January 2010-September 2011	Propane	530	(MBbls)	Index	1.28	($/gallon)	1,100
January 2010-December 2010	Isobutane	93	(MBbls)	Index	1.75	($/gallon)	717
January 2010-September 2011	Normal Butane	264	(MBbls)	Index	1.59	($/gallon)	737
January 2010-September 2011	Natural Gasoline	199	(MBbls)	Index	2.13	($/gallon)	3,068
January 2010-June 2011	West Texas Intermediate Crude	296	(MBbls)	Index	112.83	($/Bbl)	8,710
January 2010-June 2011	Natural gas	3,825,000	(MMBtu)	Index	6.07	($/MMBtu)	551
January 2010-March 5, 2010	Interest Rate	$ 300,000,000		2.40%	One-month LIBOR		(1,067)
Credit risk adjustment							(10)
						Total Fair Value	$ 8,629

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 parental guarantee.

In January 2005, one of our customers filed for Chapter 11 reorganization under U.S. bankruptcy law. The customer operates a merchant power plant, for which we provide firm transportation of natural gas. Under the contract with the customer, the customer is obligated to make fixed payments in the amount of approximately $3,200,000 per year. The contract, which expires in mid-2012, was originally secured by a $10,000,000 letter of credit. The customer accepted the firm transportation contract in bankruptcy. The customer s plan of reorganization has been confirmed by the bankruptcy court and the customer has since emerged from bankruptcy protection. In December 2005, in connection with other contract negotiations, the letter of credit was reduced to $3,300,000 and we accepted a parent guarantee in the amount of $6,700,000. At December 31, 2009, the letter of credit is $4,800,000 and customer was current in its payment obligations.

Interest Rate Risk. We are exposed to variable interest rate risk as a result of borrowings under our existing credit facility. As of December 31, 2009, we had $419,642,000 of outstanding borrowings exposed to variable interest rate risk. On February 29, 2008, we entered into two-year interest rate swaps related to $300,000,000 of borrowings under our credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (3.0 percent as of December 31, 2009) through March 5, 2010. These interest rate swaps were designated as cash flow hedges in March 2008. As a result of these interest rate swaps, an increase of 100 basis points in the LIBOR rate would increase our annual payment by $1,196,000.

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

Table of Contents

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) and 15d-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, 2009.

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 the Partnership s assets;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Partnership 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 the Partnership s assets that could have a material effect on the 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 the Partnership s internal control over financial reporting as of December 31, 2009. 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 the Partnership s internal control over financial reporting and testing of the operating effectiveness of those controls.

Based on its assessment, management has concluded that the Partnership s internal control over financial reporting was effective as of December 31, 2009.

(b) *Audit Report of the Registered Public Accounting Firm.* KPMG LLP, the independent registered public accounting firm that audited the Partnership s 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 the Partnership s 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, the Partnership s internal control over financial reporting. Based on that evaluation, there has been no change in the Partnership s 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, the Partnership s internal control over financial reporting.

Item 9B. Other Information

None.

Table of Contents

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 is not elected by our unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our General Partner or directly or indirectly participate in our management or operation.

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 is currently comprised of its Chairman (the President and Chief Executive Officer of the General Partner), three persons who qualify as independent under NASDAQ standards for audit committee members and five persons who were either appointed by the sole member of the General Partner or elected by the other members of the Board of Directors.

Corporate Governance. 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 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, nominating, and executive committees are available on our website at www.regencygasservices.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.

Conflicts Committee. The Board of Directors appoints independent directors as members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the

General Partner is fair and reasonable to us and our common unitholders. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by the General Partner or its Board of Directors of any duties they may owe us or the common unitholders. The Conflicts Committee, like the Audit Committee, is composed only of independent directors.

Audit Committee. The Board of Directors has established an Audit Committee in accordance with Exchange Act rules. The Board of Directors appointed three directors 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, John T. Mills, 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 the inclusion of our audited financial statements on this Form 10-K.

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

Risk Management Committee. The Board of Directors has established a risk management committee, which consists of three members. The committee responsibilities include identifying and reviewing the risks confronted by the Partnership with respect to its operations and financial condition, establishing limits of risk tolerance with respect to the Partnership s hedging activities and ensuring adequate property and liability insurance coverage.

Compensation and Nominating Committees. Although we are not required under NASDAQ rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee, as a limited partnership, the Board of Directors of the General Partner has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers, including the performance standards or other restrictions pertaining to the vesting of any such awards, under our existing Long Term Incentive Plan.

The Board of Directors has also appointed a Nominating Committee to assist the Board and the member of our General Partner by identifying and recommending to the Board of Directors individuals qualified to become Board members, to recommend to the Board director nominees for each committee of the Board and to advise the Board about and recommend to the Board appropriate corporate governance practices. Matters relating to the election of Directors or to Corporate Governance are addressed to and determined by the full Board of Directors.

Board Leadership Structure. The Board believes that our CEO is best situated to serve as Chairman because he is ultimately responsible for the day-to-day operation of the Partnership and is the director most familiar with the Partnership s business and industry and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Independent directors and management have different perspectives and roles in strategy development. Our non-management directors bring experience, oversight and expertise from outside the Partnership and industry, while the CEO brings company-specific experience and expertise. The Board believes that the combined role of Chairman and CEO promotes strategy development and execution, and facilitates information flow between management and the Board, which are essential to effective governance. The Board also believes that the separation of the offices of Chairman of the Board and the CEO is part of the succession-planning process and that it is in the best interests of the Partnership for the Board to make a determination regarding this issue each time it elects a new CEO.

One of the key responsibilities of the Board is to develop strategic direction and hold management accountable for the execution of strategy once it is developed. The Board believes the combined role of Chairman and CEO, together with the presence of three independent directors on the Board, is in the best interest of unitholders because it provides the appropriate balance between strategy development and independent oversight of management. The Board retains the authority to modify this structure to best address the Partnership s unique circumstances, and so advance the best interests of all unitholders, as and when appropriate.

The Board also believes, for the reasons set forth below, that its existing corporate governance practices achieve independent oversight and management accountability, which is the goal that many seek to achieve by separating the roles of the offices of Chairman of the Board and the CEO. Our governance practices provide for strong independent leadership, independent discussion among directors and for independent evaluation of, and communication with, many members of senior management. These governance practices are reflected in our Corporate Governance Guidelines and the various Committee Charters, which are available on our website. Some of the relevant processes and other corporate governance practices include:

- At regularly-scheduled Board meetings, all non-management directors meet in an executive session without our management director, who is our CEO. In these executive sessions, the non-management directors deliberate on such matters as CEO succession planning and the performance of the CEO.

- Although the Board does not have an independent lead director, the director who presides at executive sessions without the management directors rotates among the independent directors.

- Our Corporate Governance Guidelines also ensure that the non-management members of the Board are involved in key aspects of governance. For example, each director is free to suggest the inclusion of items on the agenda for each Board meeting. Additionally, the Chairman and CEO regularly solicits suggestions from the directors for presentations by management at Board and Committee meetings. Furthermore, each Board member has full and free access to our management and employees.

The Board s Role in Risk Oversight. The Board of Directors oversees 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 our audit risk assessment is presented to the Audit Committee annually; this assessment identifies internal controls risks and drives the internal audit plan for the coming year. Material violations of the 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

Table of Contents

effectiveness at both linking executive pay to performance and aligning the interests of our executives and our unitholders. The chairman of each of the Board s key committees also discusses, reviews and makes decisions on serious matters outside of quarterly Board meetings, as needed.

Meetings of Non-Management Directors and Communication with Directors. As a limited partnership, our General Partner is required to maintain a sufficient number of independent directors (as defined by the NASDAQ rules) for it to satisfy those rules regarding membership of independent directors on the Audit Committee of its Board of 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. The position of the presiding director at these meetings is rotated among the independent directors. 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.

Name	Age	Position with Regency GP LLC
Byron R. Kelley	62	Chairman of the Board, President and Chief Executive Officer
Stephen L. Arata	44	Executive Vice President and Chief Financial Officer
L. Patrick Giroir	48	Executive Vice President and Chief Commercial Officer of Gathering and Processing and Transportation Segments
Paul M. Jolas	45	Executive Vice President, Chief Legal and Administrative Officer and Secretary
David G. Marrs	56	President of Contract Compression Segment
Lawrence B. Connors	58	Senior Vice President, Finance and Chief Accounting Officer
Dennie W. Dixon	62	Senior Vice President, Operations for Gathering and Processing and Transportation Segments
Michael J. Bradley(1)(2)(4)	55	Director
James F. Burgoyne(1)	51	Director
Daniel R. Castagnola(5)(6)	43	Director
Rodney L. Gray (2)(3)	57	Director
Paul J. Halas (4)(6)	53	Director
Mark T. Mellana(4)(5)	45	Director
John T. Mills(2)(3)(5)	62	Director
Brian P. Ward(1)	50	Director

(1) Member of the Executive Committee. Mr. Burgoyne is chairman of this committee.
(2) Member of the Audit Committee. Mr. Mills is chairman of this committee.
(3) Member of Conflicts Committee. Mr. Gray is chairman of this committee.
(4) Member of Compensation Committee. Mr. Mellana is chairman of this committee.
(5) Member of Risk Management Committee. Mr. Mellana is chairman of this committee.
(6) Member of Nominating Committee. Mr. Castagnola is chairman of this committee.

Byron R. Kelley was elected Chairman of the Board of Directors of Regency GP LLC and Regency Gas Services in March 2008. Prior to his appointment, Mr. Kelley spent four years at CenterPoint Energy, which operates two interstate pipeline systems and natural gas gathering and processing systems focused on the mid-continent area. Mr. Kelley served as senior vice president and group president of pipeline and field services, and was responsible for commercial, operational, strategic, regulatory and development aspects of two business units and three lines of business. Preceding his work at CenterPoint, Mr. Kelley served as executive vice president of development, operations and engineering, and as president of El Paso Energy International in Houston, a natural gas pipeline operator. Mr. Kelley also held management and executive positions at other companies in the natural gas pipeline industry. Mr. Kelley is a past chairman and member of the Board of Directors of the Interstate National Gas Association and previously served as one of the association s representatives on the U.S. Natural Gas Council of America. Mr. Kelley received a Bachelor degree in Civil Engineering from Auburn University. Among the reasons for Mr. Kelley s appointment as a director and

Chairman of the Board are his extensive technical and executive experiences in interstate and intrastate natural gas pipelines, gathering and processing and independent power generation. His 40 years of experience spans both domestic and international activities covering operations, engineering, natural gas marketing, business development, strategic planning and executive management.

Stephen L. Arata was elected Executive Vice President and Chief Financial Officer of Regency GP LLC in September 2005. From June 2005 to the present, Mr. Arata served as Executive Vice President and Chief Financial Officer of Regency Gas Services LP and its predecessor. From September 1996 to June 2005, Mr. Arata worked for UBS Investment Bank, covering the power and pipeline sectors; he was Executive Director from 2000 through June 2005. Mr. Arata has extensive experience as a financial consultant, focusing on the energy sector. Mr. Arata received a Bachelor of Arts degree in English and a Bachelor of Business Administration degree in General Business from Southern Methodist University, and a Masters of Management from the J.L. Kellogg Graduate School of Management, Northwestern University.

L. Patrick Giroir was elected executive Vice President and Chief Commercial Officer for the Gathering and Processing and Transportation Segments of Regency GP LLC in August 2009. Prior to that Mr. Giroir served as Chief Commercial Officer for the Gathering and Processing and Transportation segments from November 2008 to August 2009. From May 2008 through November 2008, Mr. Giroir served as Senior Vice President of Strategy and Special Projects of Regency GP LLC. From October 2003 to May 2008, Mr. Giroir was with CenterPoint Energy s Pipeline Group which operates two interstate pipeline systems where he held the positions of vice president, Business Development, System Planning and Market Fundamentals and vice president, Strategic Development. Mr. Giroir received a Bachelor of Arts degree from Washington State University and a Masters of Business Administration degree from Tulane University. In addition, Mr. Giroir is a certified public accountant.

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 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.

David G. Marrs was elected President of CDM Resource Management LLC in September 2009, having served as Executive Vice President since January 15, 2008. Mr. Marrs has served in various management capacities since co-founding CDM Resource Management, Ltd. in 1997, including Executive Vice President since April 2007, Vice President Sales from July 2005 through April 2007, and Vice President Planning and Corporate Development from 1997 through June 2005. Prior to co-founding CDM Resource Management, Ltd., Mr. Marrs was employed by Contract Compression, Inc., where he served as Manager of Business Development from January, 1995 to December, 1995. Mr. Marrs received a Bachelor of Science degree from the University of Houston.

Lawrence B. Connors was elected Senior Vice President of Finance and Chief Accounting Officer of Regency GP LLC in February 2008, having served as Vice President, Finance and Chief Accounting Officer since September 2005. From December 2004 to September 2005, Mr. Connors served as Vice President, Finance and Accounting, and Chief Accounting Officer of Regency Gas Services LLC. From June 2003 through November 2004, Mr. Connors served as Controller of Regency Gas Services LLC. Prior to joining the Partnership, Mr. Connors had 24 years of experience in the energy industry in capacities involving finance, accounting, and operations. Mr. Connors is a Certified Public Accountant. Mr. Connors received a Bachelor of Business Administration with an accounting major from St. Edward s University.

Dennie W. Dixon was elected senior vice president of operations for the Gathering and Processing and Transportation segments in January 2009. Prior to working for Regency, Mr. Dixon served as an operations, pipeline and compression consultant for Arledge Gas Gathering, a gas gathering and compression services company with assets in Crockett and Val Verde Counties, Texas. From 1980 to 2004 he held various positions in the natural gas pipeline industry, most recently serving as Director of Liquefied Natural Gas for El Paso Global Gas, where he was involved with the construction and operation of LNG terminal and storage facilities. Mr. Dixon retired from El Paso after 33 years of service in 2004. Mr. Dixon received a Bachelor of Science degree in Natural Gas Engineering from Texas A&I and a Masters of Business Administration degree in Finance from the University of Houston.

Michael J. Bradley was elected to the Board of Directors of Regency GP LLC in January 2008. He has been the President and Chief Executive Officer of the Matrix Service Company since November 2006. Prior to joining Matrix Service Company, Mr. Bradley served as President and CEO of DCP Midstream Partners, a midstream MLP and was a member of the board. 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. 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. Mr. Bradley received a Bachelor of Science degree in Civil Engineering from the University of Kansas. Among the reasons for Mr. Bradley s appointment as a director are his in-depth knowledge of the midstream pipeline markets, his past extensive experience at midstream companies and his current experience as a chief executive officer of a public company providing service to the energy industry.

James F. Burgoyne was elected to the Board of Directors of Regency GP LLC in June 2007. Mr. Burgoyne is a Managing Director and global leader of GE Energy Financial Services Natural Resources business, which invests in mid- and downstream oil and gas infrastructure, producing oil, gas and coal reserves, and in a broad range of energy infrastructure in Europe. Mr. Burgoyne has headed this commercial unit within GE Energy Financial Services since it was formed in 2004. Prior to this position, Mr. Burgoyne was a Managing Director with GE Structured Finance s global energy team, where he was responsible for client development and the origination of business opportunities with US energy companies domestically and internationally. Before joining GE in 1997, Mr. Burgoyne was an Executive Director at SBC Warburg. Mr. Burgoyne received a Bachelor of Commerce degree from McGill University and a Masters of Management, Finance, from Northwestern University. Among the reasons for Mr. Burgoyne s appointment as a director are his deep experience in energy markets generally, and those pertaining to natural gas and oil in particular, along with his understanding of corporate finance and his strategic overview of the energy industry.

Daniel R. Castagnola was elected to the Board of Directors of Regency GP LLC in June 2007. Mr. Castagnola is a Managing Director at GE Energy Financial Services and is responsible for a team of professionals investing in oil and gas infrastructure in North America. Additionally, Mr. Castagnola leads a broad range of energy infrastructure origination efforts, including power, renewable, oil and gas and oil field services investments in Latin America, Mr. Castagnola joined GE in 2002. Prior to joining GE, Mr. Castagnola worked for nine years at an international energy firm and three years at a public accounting firm. Mr. Castagnola received a Bachelor degree and a Masters degree in Business Administration, both from the University of Houston. Among the reasons for Mr. Castagnola s appointment as a director are his in-depth knowledge of the midstream and contiguous markets, his familiarity with the Partnership and its opportunities, and his skills in identifying and executing transactions and financing options.

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.

Paul J. Halas was elected to the Board of Directors of Regency GP LLC in June 2007. From June 2006 to the present, Mr. Halas has served as a Managing Director and General Counsel of GE Energy Financial Services. Mr. Halas served as the Senior Vice President Business Development at the National Grid USA Service Company Inc., a provider of natural gas and electricity delivery in the New England/New York region, from May 2005 to June 2006. From August 2003 to May 2005, Mr. Halas served as the President of GridAmerica LLC (Independent Electric Transmission Company, subsidiary of National Grid USA). He also served as Senior VP & General Counsel of GridAmerica LLC from May 2002 to August 2003. Mr. Halas received a Bachelor of Arts degree in Economics and a Juris Doctor degree, both from Harvard University. Among the reasons for Mr. Halas appointment as a director are his broad experience as an executive of and advisor to public companies on securities law matters and transactions, and his familiarity with the energy industry, regulation and transactions.

Mark T. Mellana was elected to the Board of Directors of Regency GP LLC in June 2007. Mr. Mellana is a Managing Director at GE Energy Financial Services, which provides financial solutions, such as structured equity, leveraged leasing, partnership project finance and broad based financial solutions, to the global energy industry, and has been with the firm since 1999. Mr. Mellana has held various positions at GE Energy Financial Services and is currently a Managing Director Operations and Development responsible for equity and development investments. Mr. Mellana serves on a number of boards, including those of Source Gas LLC, a local gas distribution company serving customers in Colorado, Nebraska and Wyoming, and Bobcat Gas Storage LLC, which is developing an underground natural gas storage facility in Landry Parish, Louisiana. Mr. Mellana received a Bachelor of Science degree in Electrical Engineering from Villanova University and a Masters degree in Business Administration from Boston University. Among the reasons for Mr. Mellana s appointment as a director are his deep understanding of the broad energy industry and regulation, as well as his skills in executing transactions and driving efficiency in the integration of companies and their operations.

John T. Mills was elected to the Board of Directors of Regency GP LLC in January 2008. Since 2006, Mr. Mills has served on the Board of Directors of and as a member of the audit and compensation committees of CONSOL Energy (NYSE: CNX), the largest producer of high-Btu bituminous coal in the United States. Currently, Mr. Mills also serves as a member of the audit, compensation, and corporate governance and nominating committees for Cal Dive International Inc. (NYSE: DVR), a marine construction company. Prior to his board appointments, Mills spent 30 years in numerous management and tax-related positions, including his most recent role as chief financial officer for Marathon Oil, a major integrated energy company, until his retirement in 2003. Mr. Mills received a Bachelor of Arts degree in Economics from Ohio University and a Juris Doctor degree from the Ohio State University. Among the reasons for Mr. Mills appointment as a director are his financial expertise as an international energy company financial executive and his experience serving on the boards of other energy and energy service companies.

Brian P. Ward was elected to the Board of Directors of Regency GP LLC in June 2007. Mr. Ward is Managing Director and Chief Risk Officer for GE Energy Financial Services, which provides financial solutions, such as structured equity, leveraged leasing, partnership project finance and broad based financial solutions, to the global energy industry. In this role, Mr. Ward is responsible for underwriting and portfolio risk management for GE Energy Financial Services domestic and international assets. Mr. Ward has held this position since January 2004. Immediately prior to joining this unit, Mr. Ward served as Quality Leader for GE Structured Finance, the predecessor business of GE Energy Financial Services. Mr. Ward has worked for GE for more than 25 years. Mr. Ward received a Bachelor of Science degree in Business Administration from the State University of New York at Oswego. Among the reasons for Mr. Ward s appointment as a director are his deep understanding of the risks and returns of infrastructure assets, in particular energy infrastructure assets, and his experience in evaluating transactional opportunities, executing them and incorporating them into a coherent growth strategy.

Reimbursement of Expenses of Our General Partner. Our General Partner will not receive any management fee or other compensation for its management of our partnership. Our General Partner will, however, be reimbursed for all expenses incurred on our behalf. These expenses include the cost of employee, officer and director compensation and benefits properly allocable to us and all other expenses necessary or appropriate to the

Table of Contents

conduct of our business and allocable to us. The partnership agreement provides that our General Partner will determine the expenses that are allocable to us. There is no limit on the amount of expenses for which our General Partner may be reimbursed.

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, 2009 our General Partner s officers, directors and greater than ten percent common unitholders filed all reports they were required to file under Section 16(a). A Form 4 for each of Stephen L. Arata and Lawrence B. Connors reflecting the conversion of subordinated units into common units on February 17, 2009 was filed on February 17, 2010, due to an administrative error. In addition, a Form 4 for Dennie W. Dixon reflecting the conversion of restricted units into common units on February 2, 2009 was filed on February 24, 2010, due to an administrative error.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

Overview of Our Executive Compensation Program

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 :

Byron R. Kelley, Chairman of the Board, President and Chief Executive Officer

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

David G. Marrs, President of Contract Compression Segment

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

Dennie W. Dixon, Senior Vice President, Operations for Gathering and Processing and Transportation Segments

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.

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 directors and executive officers. The Committee is directly responsible for the General Partner s compensation programs, which include programs that are designed specifically for our senior officers, including our Named Executive Officers.

Table of Contents

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. These compensation programs for executive officers consist of base salary, annual incentive bonus and Long Term Incentive Plan (LTIP) awards in the form of equity-based restricted units and phantom units, as well as other customary employment benefits. Total compensation of executive officers and the relative emphasis of the three main components of compensation are reviewed on an annual basis by the Committee, which then 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 magnitude of the annual incentive bonus pool to be paid to executive officers and employees for the preceding year.

It is the practice of the Committee to meet in person or by conference call at least twice a year for several purposes. These include (a) assessing the performance of the CEO and other senior officers with respect to the Partnership results for the preceding year, (b) reviewing and assessing the personal performance objectives of the senior officers for the preceding year, and (c) determining the amount of the bonus pool approved by the Board to be paid to the executive officers after taking into account both the target bonus levels established for those executive officers at the outset of the preceding year and the foregoing performance factors. 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 paid to executives and senior management, other than the CEO.

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, as well as our other employees.

Compensation Philosophy and Objectives

The principal objective of our compensation program is to attract and retain, as executive officers and employees, individuals of demonstrated competence, experience and leadership in our industry and in those professions required by our business 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 sustainable earnings and cash available for distribution;
- to reward participants for value creation commensurate with competitive industry standards;
- to provide a significant percentage of total compensation that is at-risk or variable;
- to encourage significant equity ownership to align the interests of executive officers and key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship, cooperation among business units and employee pay.

Table of Contents

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 the performance of the Partnership, the Committee considers the following financial and operating measures:

- Adjusted EBITDA, which we define as net income (loss) plus interest expense, provision for income taxes, depreciation and amortization expense, non-cash losses (gains) from derivatives, losses (gains) on asset sales, net, loss on debt refinancing, other expense (income), net, and 100 percent of the adjusted EBITDA earned by HPC for the period; less equity method income from HPC for the period. The definition for Adjusted EBITDA used for compensation purposes differs from Adjusted EBITDA used in Item 6 Selected Financial Data and Item 7 Management Discussion and Analysis of Financial Condition and Results of Operations. Adjusted EBITDA used in Item 11 Executive Compensation assumes the Partnership owns 100 percent of HPC;
- the amount of distributions paid with respect to all of our outstanding common units;
- costs associated with the recently-completed Haynesville Expansion Project;
- 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.

The Committee elected to utilize these measures for gauging the performance of the Partnership in 2009 as a means of incentivizing executives to meet our financial goals, to deliver growth in unitholder value, to execute the Haynesville Expansion Project on time and under budget, and to ensure the safety of our employees, the environment, and the communities in which we operate.

Market Analysis

In 2009, to ensure that our compensation practices were competitive, the Committee retained BDO Seidman, LLP, to provide a total compensation analysis for 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, we also rely on the expertise of BDO Seidman, LLP in order to obtain a more complete picture of the overall compensation environment.

83

Table of Contents

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 the Partnership achieves its 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 experience, skills or tenure with us, changes to the individual s position, or 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 or 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.

Elements of the 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.	Keep our annual compensation competitive with the defined market for skills and experience necessary to execute the Partnership s business.
Annual incentive bonus	Performance-based annual cash incentive earned based on achievement of corporate objectives and individual performance against target performance levels; awards are targeted to range between the 50th and the 75th percentile.	Align performance to the corporate objectives that drive the Partnership s 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.

84

Table of Contents

Element	Characteristics	Purpose
Equity based awards (phantom units)	Awards are based on performance of the Partnership and competitive practices at peer companies. Forfeiture restrictions lapse according to the passage of time or the achievement of certain metrics relative to our peer companies. In general, units with time-based restrictions vest as to 1/3 of the award on each of the first three anniversaries of the award date. Units with market-based restrictions vest at the end of three years if the particular performance measure has been achieved. Distribution equivalent rights (DERS) accompany equity grants, but the right to distributions does not vest until the right to the underlying unit vests. Equity awards granted in prior years consisted of restricted units that were subject to different vesting provisions, both as to the restricted 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 delayed vesting schedule facilitates retention of executive officers.
Equity based awards (Class C Units) in our General Partner	Class C units in our General Partner are a separate class of securities representing an economic interest in our General Partner. These units are structured as management incentive equity with forfeiture provisions in the grant documents that lapse upon achievement of certain levels of distributable cash on a per unit basis.	Align the interest of executive officers with unitholders and reward executives for value creation associated with the Partnership.
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 2009). The Partnership matches a participant s contributions to the 401(k) plan, up to six percent of eligible compensation, but not greater than $16,500. Employer s matching contributions vest ratably over three years.	Provide employees with the opportunity 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.	Provides benefits to meet the health and wellness needs of employees and their families.

Table of Contents

Compensation Components and Analysis

Base Salary

Design. Base salaries are targeted at market median levels, 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.

2009 Fiscal Year Results. Due to changes in industry pay practices resulting from the impact of the significant downturn in economic conditions, the Committee elected to defer 2009 salary adjustments for employees until July 2009. Effective as of July 6, 2009, the Committee made the following decisions with respect to salary adjustments:

Named Executive Officer	2009 Salary	Percentage Increase Over Prior Year
Byron R. Kelley	$ 489,250	3%
Stephen L. Arata	$ 283,300	3%
David G. Marrs	$ 300,000	24%
L. Patrick Giroir	$ 236,500	10%
Dennie Dixon	$ 215,300	2.5%

The base salary increases for Messrs. Kelley, Arata and Dixon represented an increase of approximately 3 percent, which was consistent with the marketplace. Mr. Marrs base salary increase was due to his promotion to Division President. Mr. Giroir s salary increase was due to promotion to Executive Vice President and Chief Commercial Officer.

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. Arata, Marrs and Dixon fall within five percent of the 50th percentile of salaries of individuals in comparable positions at our peer group of companies. Mr. Kelley s base salary is 14 percent higher than that of a CEO at the 50th percentile of our peer group of companies, which increase continues to reflect the results of salary negotiations necessary to hire Mr. Kelley as our CEO in 2008. Salary increases for Mr. Kelley since his hire date have been consistent with market increases. Mr. Giroir s salary is 14 percent lower than the salary of an employee in a comparable position compensated at the 50th percentile of our peer group of companies. This deviation from the 50th percentile is a result of Mr. Giroir s mid-year promotion from Senior Vice President to Executive Vice President.

Changes for Fiscal Year 2010. At its meeting on February 24, 2010, the Committee discussed salary data for our peer group of companies, our annual performance targets for individual officers, and general economic conditions and challenges facing the Partnership in this fiscal year. The Committee decided to defer any decisions related to base salary increases until its meeting in May 2010.

Annual Incentive Bonuses

Design. Annual incentive bonuses are targeted to range between the 50th and 75th percentile of our peer group of companies. If target goals are achieved, each Named Executive Officer is eligible to receive an annual bonus opportunity ranging from 75 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 upon the achievement of certain Partnership performance goals. At the beginning of 2009, the Committee approved a total target bonus pool of $11,575,329, which was based on the sum of each employee s target bonus opportunity, expressed as a percentage of each employee s base salary. For 2009, whether the Partnership funded the total amount of the target bonus pool depended upon Partnership performance related to the following corporate performance measures:

- Adjusted EBITDA, which we define as net income (loss) plus interest expense, provision for income taxes, depreciation and amortization expense, non-cash losses (gains) from derivatives, losses (gains) on asset sales, net, loss on debt refinancing, other expense (income), net, and 100 percent of the adjusted EBITDA earned by HPC for the period; less equity method income from HPC for the period. The definition for Adjusted EBITDA used for compensation purposes differs from Adjusted EBITDA used in Item 6 Selected Financial Data and Item 7 Management Discussion and Analysis of Financial Condition and Results of Operations. Adjusted EBITDA used in Item 11 Executive Compensation assumes the Partnership owns 100 percent of HPC;

- the amount of distributions paid with respect to all of our outstanding common units;

- costs associated with the recently-completed Haynesville Expansion Project;

- 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. If threshold performance is achieved for each metric, then 50 percent of the potential bonus pool will accrue for distribution. If target performance is achieved for each metric, 100 percent of the potential bonus pool will accrue. If stretch performance is achieved for each metric, then 175 percent of the potential bonus pool will accrue for distribution. The Committee has the discretion to apply a zero to two times multiplier to the amount of the final bonus pool, resulting in the potential of zero to up to 350 percent bonus pool accrual. This discretionary multiplier is meant to reward extraordinary corporate performance, or to reduce the bonus pool accrual as a response to current business conditions or other factors. In 2009, the Committee exercised its discretion and elected to increase the amount of the Partnership-wide bonus pool by 18 percent, as described more fully below.

The annual incentive bonus pool is prorated if actual performance falls between the defined threshold and stretch corporate performance targets. For 2009, the corporate performance targets were:

Performance Metric	Threshold	Target	Stretch	Weight %
Adjusted EBITDA assume 100 percent ownership of HPC (millions)	$ 226.7	$ 238.6	$ 257.7	50%
Per Unit Cash Distributions	$ 1.68	$ 1.78	$ 1.78	20%
Haynesville Expansion Costs (millions)	$ 653	$ 643	$ 617	20%
Total Reportable Incident Rate	2.25	2.05	1.80	5%
Preventable Vehicle Accidents	16	14	11	5%
Total Bonus Payout				100%

Table of Contents

Once the Committee decides the funding of the Partnership wide bonus pool based upon 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 2009, our NEOs were members of the Corporate, CDM, Commercial Operations and Gathering, Processing and Transportations (GP&T) Operations groups. At the beginning of 2009, the Committee approved target bonus pools for each of these business groups in the following amounts:

Business Group	Target Bonus Pool
Corporate	$ 3,697,430
CDM	5,462,829
Commercial Operations	692,467
GP&T Operations	1,722,603
Total	$ 11,575,329

These amounts represent the sum of the target bonus opportunity for each employee in an individual business group, determined as a percentage of each employee s base salary. The Committee also set business group-specific performance targets for each of the Corporate, CDM, Commercial Operations and GP&T Operations groups, the achievement of which determines the size of the bonus pool available to each group. The following chart describes the group-specific performance objectives for each group and the weighting given to company performance targets and group-specific performance targets for use in determining the size of the bonus pool for Corporate, CDM, Commercial Operations and GP&T Operations groups:

Corporate Group Performance Targets

	Bonus Pool Determination				Impact on Bonus		
Performance Metric	**Threshold**	**Target**	**Stretch**	**Weight %**	**Threshold**	**Target**	**Stretch**
Corporate Performance Goals	Partnership Performance	Partnership Performance	Partnership Performance	90%	45%	90%	157.5%
Corporate Group-Specific Goal							
General and Administrative Expense (in millions)	$ 27.0	$ 25.7	$ 23.7	10%	5%	10%	17.5%
Total Bonus Payout				100%	50%	100%	175%

CDM Group Performance Targets

	Bonus Pool Determination				Impact on Bonus		
Performance Metric	**Threshold**	**Target**	**Stretch**	**Weight %**	**Threshold**	**Target**	**Stretch**
Corporate Performance Goals	Partnership Performance	Partnership Performance	Partnership Performance	20%	10%	20%	35%
CDM Group-Specific Goal							
Total Reportable Incident Rate	2.2	1.8	1.6	5%	2.5%	5%	8.75%
Preventable Vehicle Accidents	7	5	4	5%	2.5%	5%	8.75%
CDM EBITDAR (in millions)	$ 77.3	$ 81.4	$ 87.9	40%	20%	40%	70%
Controllable Expenses (G&A/O&M) as a percentage of total revenue	55.0%	52.4%	48.2%	20%	10%	20%	35%
Budgeted Regency Compression Charges ($/hp/month)	$ 5.32	$ 5.07	$ 4.66	10%	5%	10%	17.5%
Total Bonus Payout				100%	50%	100%	175%

Table of Contents

Commercial Operations Group Performance Targets

Performance Metric	Bonus Pool Determination Threshold	Target	Stretch	Weight %	Impact on Bonus Threshold	Target	Stretch
Corporate Performance Goals	Partnership Performance	Partnership Performance	Partnership Performance	20%	10%	20%	35%
General and Administrative Goals ($ in millions)	$ 6.3	$ 6.0	$ 5.6	20%	10%	20%	35%
Gross Margin Goals ($ in millions)	$ 205.1	$ 215.9	$ 233.1	60%	30%	60%	105%
Total Bonus Payout				100%	50%	100%	175%

GP&T Operations Group Performance Targets

Performance Metric	Bonus Pool Determination Threshold	Target	Stretch	Weight %	Impact on Bonus Threshold	Target	Stretch
Corporate Performance Goals	Partnership Performance	Partnership Performance	Partnership Performance	20%	10%	20%	30%
GP&T Operations Group-Specific Goals							
Total Reportable Incident Rate	2.5	2.2	2	5%	2.5%	5%	7.5%
Preventable Vehicle Accidents	11	9	7	5%	2.5%	5%	7.5%
Notice of Violation/Notice of Enforcement	1	0	0	5%	2.5%	5%	5%
General and Administrative and Operations and Maintenance Expense (in millions)	$ 51.0	$ 48.6	$ 44.7	45%	22.5%	45%	90%
Maintenance Capex (in millions)	$ 11.1	$ 10.6	$ 9.7	20%	10%	20%	35%
Total Bonus Payout				100%	50%	100%	175%

The CEO has discretion to allocate between ten 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 based upon each NEO s personal performance during the year, and on the performance of the business group of which the NEO is a member. 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.

Table of Contents

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 2009 represented.

Named Executive Officer	Target Performance	Annual Incentive Bonus Award as a % of Salary
Byron R. Kelley	100%	87%
Stephen L. Arata	75%	60%
David G. Marrs	90%	72%
L. Patrick Giroir	75%	56%
Dennie Dixon	75%	64%

Fiscal Year 2009 Results. The following chart shows our 2009 actual results:

Performance Metric	Financial Results
Adjusted EBITDA assume 100 percent ownership of HPC	$ 222,217,869
Per Common Unit Cash Distributions	$ 1.78
Haynesville Expansion Cost	$ 615,000,000
Total Reportable Incident Rate	2.42
Preventable Vehicle Accidents	8

The Partnership did not meet the corporate performance target for Adjusted EBITDA or the Total Reportable Incident Rate, but met or exceeded the corporate performance target for per unit cash distributions, Haynesville Expansion Projects costs and preventable vehicle accidents, which would have produced a funding of the total bonus pool of 67.5 percent of target. However, the Committee exercised its discretion and elected to increase the funding of the Partnership bonus pool to 80 percent (an 18 percent increase over the original bonus pool), based upon its recognition that the Partnership set the target for Adjusted EBITDA before the contribution of RIGS to HPC. The Adjusted EBITDA metric established at the beginning of 2009 measured the Partnership on a 100 percent of HPC s Adjusted EBITDA and did not account for the fact that the Partnership owned less than 100 percent of HPC. Subsequent to establishing this metric, the Committee determined that using the Partnership s proportionate share of HPC s adjusted EBITDA rather than 100 percent was more appropriate. Funding of the Partnership s bonus pool using an Adjusted EBITDA metric based solely upon its proportionate ownership of HPC would have resulted in a funding of the Partnership bonus pool at 98 percent of target. Rather than fund the Partnership bonus pool at 98 percent of target, the Committee funded the Partnership bonus pool at 80 percent of target. The Committee s decision was based upon its desire to calibrate the performance metrics to appropriately account for the Partnership s ownership in HPC and to recognize the Partnership s achievement of several performance metrics at stretch levels, but also to maintain compensation commensurate with Partnership performance at financially responsible levels.

Allocation of Bonus Pool Among Business Groups.

The following tables describe the performance results of each of the business groups of which our NEOs are members with regard to the individual performance targets for each group:

Corporate Group Results

Performance Metric	Results
General and Administrative Expense (in millions)	$ 23.6

Table of Contents

CDM Group Results

Performance Metric	Results
Total Reportable Incident Rate	2.9
Preventable Vehicle Accidents	3
CDM EBITDAR (in millions)	$ 78.5
Controllable Expenses (G&A/O&M as percentage of total revenue)	47.6
Budgeted Regency Compression Charges ($/hp/month)	$ 6.4

Commercial Operations Group Results

Performance Metric	Results
G&A Goals (in millions)	$ 5.9
Gross Margin Goals (in millions)	$ 206.0

GP&T Operations Group Results

Performance Metric	Results
Total Reportable Incident Rate	1.7
Preventable Vehicle Accidents	5
Notice of Violation/Notice of Enforcement	2
G&A and O&M expense (in millions)	$ 46.4
Maintenance Capex (in millions)	$ 13.9

The Committee evaluated each business group s achievement of its performance metrics and determined the percentage of the business group s target bonus pool to which the group was entitled, based upon the performance of the Partnership, the performance of the business group and the weighting assigned to the performance metrics. Mr. Kelley then exercised his discretion as CEO to reallocate the bonus pool among the different business groups. In 2009, the Commercial Operations group had stretch gross margin goals associated with the early completion of the Haynesville Expansion Project. The Haynesville Expansion Project was not completed by November 2009, due to record rainfall and flooding in the Haynesville area, which impacted the schedule for completion and made it impossible for the Commercial Operations group to achieve its stretch goal. Based upon his assessment of gross margin stretch goals, which were impacted by the record rainfall during construction, Mr. Kelley elected to increase the size of the bonus pool for the Commercial Operations group. The following table shows the percentage of target bonus pools to which the individual business groups were entitled based upon their performance and compares that percentage against the final allocation which was adjusted based upon the recommendation of our CEO for the extraordinary events facing the Commercial Operations group in the last quarter of 2009:

Bonus Pool Allocation

Business Group	Percentage of Target Bonus Pool Based Upon Achievement of Performance Metrics	Percentage of Target Bonus Pool Based Upon CEO Reallocation
Corporate	75.7	75.0
CDM	72.4	75.0
Commercial Operations	62.0	72.0
GP&T Operations	85.3	85.0

Bonus Awards

Once the company-wide bonus pool was allocated among the various business groups, our CEO assessed the performance of each of our NEOs in 2009. This assessment considers performance measured against specific group targets with subjective adjustments based on a range of factors that may vary for each of the NEO s. The CEO then made recommendations to the Committee regarding the NEOs (exclusive of the CEO), which then considered the performance of the CEO and the NEOs and approved the following bonus amounts for each NEO:

Named Executive Officer	2009 Annual Incentive Bonus Award
Byron R. Kelley	$ 425,000
Stephen L. Arata	170,000
David G. Marrs	216,000
L. Patrick Giroir	133,000
Dennie Dixon	137,500

In general, the bonus amounts approved for each NEO for 2009 were consistent with the funding of the company-wide bonus pool at 80 percent of target, and the funding of the individual bonus groups bonus pools at between 72 and 85 percent of target amounts. Bonuses awarded to the Partnership s NEOs fell within a range of 75 to 87 percent of the individual NEO s bonus target, expressed as a percentage of the NEO s salary. The range of bonus awards reflects the performance of individual NEOs, the particular challenges facing a NEO or a business group in 2009, and significant individual accomplishments throughout the year.

Changes for Fiscal Year 2010.

As of the time of filing of this Compensation Discussion and Analysis, the Committee has not approved any changes to the annual incentive compensation program for fiscal year 2010. If the Committee makes any material changes to the annual incentive compensation program, those changes will be disclosed on a Form 8-K.

Equity-Based Awards

Design. The LTIP was adopted at the time of the IPO of the Partnership in 2006. In adopting the LTIP, our Board of Directors recognized that it needed a source of equity to attract new members to the management team, as well as to provide an equity incentive to other key employees. We believe the LTIP promotes a long-term focus on results and aligns employee and unitholder interests.

Equity awards are granted under our LTIP and are targeted at median market levels, though awards in a particular year are a result of a number of factors, including the availability of a pool of equity units from which to make awards. In reviewing equity-based awards to executive officers, including options, restricted units, phantom units and distribution rights, the Committee gives consideration to the number of such awards already held by each individual. Equity-based awards may be awarded to executive officers at the commencement of their employment, annually on meeting corporate and individual objectives, and from time to time by the Committee based on regular assessments of the compensation levels of comparable companies.

In 2009, the Committee made several changes to our equity compensation program. First, equity awards made in 2009 may be subject to forfeiture restrictions that lapse based on the passage of time or the achievement of certain performance measures relative to our peer companies. Awards that are subject to time-based forfeiture restrictions vest as to one-third of the award on each of the first three anniversaries of the date of the award. Awards subject to market-based forfeiture restrictions vest at the end of three years, but only if the Total Unitholder Return (TUR), as defined below, of the Partnership s common units ranks at or above the 40th percentile of the TUR of the common units of its peer group. 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

Table of Contents

at the beginning of that specified period. At the end of three years, an award of market-based units will vest according to the following schedule:

Percentile Ranking of Partnership s TUR Against Peer Group Members TUR	Below 40th Percentile	40th Percentile (Threshold)	60th Percentile (Target)	75th Percentile (Maximum)
Vested Percentage (Market-Based Awards)	0% of units vest	50% of units vest	100% of units vest	150% of units vest

Where the Partnership s results fall between the threshold, target and maximum percentile groups, a corresponding percentage of units between the threshold, target and maximum percentage amounts also will vest.

In addition, the Committee made changes to an award recipient s rights to any distribution equivalent rights (DERs) that may accompany the award of a phantom unit under the LTIP. A DER entitles the grantee to a cash payment equal to the cash distributions made with respect to a unit while such phantom unit is outstanding. In previous years, the recipient of an equity award that was accompanied by DERs was entitled to the DERs as distributions were made. Beginning in 2009, any DERs accumulated during the period before an award has vested are recorded as a liability on the Partnership s balance sheet until the right to the underlying unit vests. When the grantee s ownership of the unit vests, he or she is then entitled to any DERs that have accrued before vesting from the grant date.

Phantom Units. Phantom units entitle the holder to receive a unit of the Partnership s common units or an amount of cash equal to the fair market value of a unit of common unit, as determined by the Committee, upon the vesting of the phantom unit. Phantom units may be subject to a time-based or a market-based vesting schedule. DERs may be granted in tandem with phantom units and DERs accompanying phantom units awarded in 2009 are subject to the vesting schedule of the phantom unit awarded.

2009 Fiscal Year Results. In 2009, the dollar value of equity awards was meant to approximate the market median of the dollar value of equity awards made by our peer group of companies. We granted equity to our Named Executive Officers in connection with their total direct compensation. For each grant of equity awards in 2009, 40 percent of the aggregate award is subject to vesting restrictions that lapse according to the passage of time, and 60 percent of the award is subject to a market-based vesting restrictions that lapse based upon achievement of TUR targets. Any DERs awarded in conjunction with equity awards vest at the time the underlying equity award vests.

For 2009, the Committee made the following phantom unit awards to NEOs, each of which includes a tandem DER subject to the vesting schedule of the phantom unit awarded:

Named Executive Officer	Total Number of Units Awarded
Byron R. Kelley	40,000
Stephen L. Arata	20,000
David G. Marrs	22,000
L. Patrick Giroir	10,000
Dennie Dixon	8,000

In addition to the 8,000 phantom units awarded to Mr. Dixon under the Partnership s LTIP, Mr. Dixon received 15,000 restricted units with tandem DERs in a one-time grant as part of his compensation negotiations to join the Partnership. The 15,000 units awarded to Mr. Dixon as part of our employment of him are subject to restrictions that lapse as to 25 percent of the award on each of the first four anniversaries of the date of grant (February 2, 2009). The Partnership awarded Mr. Dixon restricted units as part of his total compensation in order to offer a pay package competitive with those offered by our peer group of companies. The size of the award was determined in consultation with our outside pay consultant, who advised us regarding the range of equity awards granted as part of salary negotiations among our peer companies.

Changes for Fiscal Year 2010. At its meeting in February 2010, the Committee did not make any changes to long-term incentive compensation for fiscal year 2010.

Class C Units. Class C Units in our General Partner are structured as management incentive equity and the vesting of these units will entitle the holders to participate in quarterly distributions or incentive distributions by the Partnership attributable to the interests in our General Partner. The Class C Units, as a whole, will participate in those distributions based on the level of distributable cash per unit produced by the Partnership (without regard to incentive distribution rights): at the annual level of less than $2.50 per common unit, no participation; $2.50 - $2.74, two percent of the distributions received; $2.75 - $2.99, five percent of the distributions received; and $3.00 or more, ten percent of the distributions received. The Class C Units vest at the time a level of participation is achieved and vest at that level (until another level is achieved). If the employment of a holder of Class C Units is terminated for any reason, including death or disability, any unvested Class C Units will be forfeited to General Electric Energy Financial Services and will be available for reissuance or reallocation.

The receipt of any distributions with respect to the Class C Units is subject to contingencies relating to the levels of cash available for distribution by the Partnership on the common units (described above) and to the continued employment of the holders of the units. The Class C Units are not yet entitled to any distributions and none have vested. Accordingly, no value has been assigned to the Class C Units and none has been included in the summary compensation table.

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 2009. The Partnership matches dollar for dollar up to 6 percent of eligible compensation. Decisions regarding this element of compensation do not impact any other element of compensation. Vesting of employer s matching contribution are ratably over three years.

Perquisites

Perquisites are not a significant factor in our compensation structure. During salary negotiations, the Partnership agreed to provide Mr. Kelley with a $4,500 per month housing allowance until Mr. Kelley elects to relocate his family to Dallas, Texas. Also as part of salary negotiations, the Partnership agreed to provide Mr. Giroir with a housing allowance of $3,333 per month. Mr. Giroir s housing allowance will end in May 2010. Mr. Dixon received a one-time payment of $20,541 as a resettlement allowance, which amount was agreed to during Mr. Dixon s salary negotiations when he joined the Partnership.

Employment Agreements, Severance Benefits and Change in Control Provisions

We maintain employment and other compensatory agreements with some of our corporate 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 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. These agreements are described in more detail elsewhere in this document. Please read Executive Compensation Potential Payments Upon a Termination or Change in 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 current legislative policies, economic and market conditions.

Class B Units

In conjunction with General Electric Energy Financial Service s acquisition 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.

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, 2009 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

Mark T. Mellana, Chairman

Michael J. Bradley

Paul J. Halas

Table of Contents

COMPENSATION TABLES AND NARRATIVES

Summary Compensation Table for 2009

Name and Principal Position	Year	Salary ($)	Stock Awards ($)(2)	Non Equity Incentive Plan Compensation ($)	All Other Compensation ($)(3)(4)	Total ($)
Byron R. Kelley(1) (5)	2009	480,481	333,520	425,000	264,484	1,503,485
Chairman of the Board, President and Chief Executive Officer	2008	356,250	2,813,761	400,000	72,189	3,642,200
Stephen L. Arata (5)	2009	278,192	166,760	170,000	17,329	632,281
	2008	268,750		208,200	10,029	486,979
Executive Vice President and						
Chief Financial Officer	2007	250,000		127,875	10,324	388,199
David G. Marrs(1) (5)	2009	260,671	183,436	216,000	15,942	676,049
President of Contract Compression Segment						
L. Patrick Giroir(1) (5)	2009	223,021	83,380	133,000	88,960	528,361
Executive Vice President and Chief Commercial Officer of Gathering and Processing and Transportation Segments						
Dennie Dixon(1) (5)	2009	187,808	230,204	137,500	56,244	611,756
Senior Vice President, GP&T						

(1) Mr. Kelley was not a Named Executive Officer in 2007 and therefore information is not provided for that year. Compensation values reported in the Summary Compensation Table for Messrs. Marrs, Giroir and Dixon include only amounts related to 2009 as each became a Named Executive Officer in 2009.

(2) 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, 2009 and 2008, computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in Note 16 to the audited financial statements included this Annual Report for the fiscal year ended December 31, 2009. 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 $5.59 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 Topic 718) is satisfied.

(3) The amount includes the Partnership contribution to its 401(k) plan on behalf of the Named Executive Officer.

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

Name	Year	Distributions	Living Expenses	Moving Expenses	Company 401(k) Match	Insurance Gross-Up
Byron R. Kelley	2009	172,526	54,000	20,605	16,500	853
Stephen L. Arata	2009				16,500	829
David G. Marrs	2009				15,640	302
L. Patrick Giroir	2009	43,017	38,462		6,716	765
Dennie Dixon	2009	26,700		20,541	8,385	618

(a) Distributions are amounts paid to Messrs. Kelley, Giroir and Dixon related to awards of restricted units made under the LTIP in prior years.

(5) The summary compensation table excludes Class C Units of our General Partner. Mr. Kelley, Mr. Arata, Mr. Marrs, Mr. Giroir, and Mr. Dixon own 85, 60, 40, 20, and 20, respectively.

Table of Contents

Other than housing and moving expenses provided to Messrs. Kelley, Giroir and Dixon, 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, 2009.

Grants of Plan-Based Awards

For the Year Ended December 31, 2009

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards	Grant Date Fair Value
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**Number of Shares of Stock or Units (#)**	**of Stock and Option Awards**
Byron R. Kelley	5/27/2009	244,625	489,250	856,188	12,000	24,000	36,000	16,000	199,360
Stephen L. Arata	5/27/2009	106,238	212,475	371,831	6,000	12,000	18,000	8,000	99,680
David Marrs	9/01/2009	135,000	270,000	472,500	6,600	13,200	19,800	8,800	109,648
L. Patrick Giroir	5/27/2009	88,688	177,375	310,406	3,000	6,000	9,000	4,000	49,840
Dennie Dixon	2/02/2009	80,738	161,475	282,581				15,000	163,500
	5/27/2009				2,400	4,800	7,200	3,200	39,872

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 2009.

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 will terminate on April 1, 2010, subject to additional one-year extensions until either the Partnership or Mr. Kelley gives at least one-year s prior written notice of non-renewal. Mr. Kelley s annual base salary is $489,250, subject to increases by the Committee and a monthly living allowance of $4,500. Under the employment agreement, Mr. Kelley is eligible to participate in the annual bonus plan, and will have a target bonus equal to his annual base salary; provided that Mr. Kelley will receive a minimum bonus for 2009 of $200,000 regardless of any performance criteria achieved.

Mr. Kelley was also awarded 85 Class C Units of our General Partner. The Class C Units are not yet entitled to any distributions. Please read the section entitled Compensation Discussion and Analysis Compensation Components and Analysis Equity-Based Awards Class C Units for a description of the material terms of the Class C Units.

David G. Marrs: Effective 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. The agreement will terminate on September 1, 2011, subject to additional one-year extensions until either the Partnership or Mr. Marrs gives at least one year s prior written notice of non-renewal. Under the terms of the agreement, Mr. Marrs base salary is $300,000, subject to annual reviews and increases by the Committee, and he is eligible for an annual performance bonus of up to 90 percent of his base salary. Pursuant to the terms of the agreement, Mr. Marrs was also awarded 22,000 phantom units subject to the terms of the LTIP.

Table of Contents

Phantom Units

Awards reported for 2009 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 2009 are subject to restrictions that lapse according to the passage of time or the achievement of certain performance measures relative to our peer companies. In general, 40 percent of units awarded in 2009 are subject to restrictions that lapse according to the passage of time, and 60 percent are subject to restrictions that lapse based upon the Partnership s achievement of certain levels of TUR, as compared to its peers. 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. 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 in Control Termination of Employment or Change in Control under our LTIP . Phantom units 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. 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 2009, 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 in Control .

Options

No options were granted during fiscal year 2009.

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 in 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 in Columns (c) through (e) of the Grants of Plan-Based Awards Table are described in the Compensation Discussion and Analysis above.

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
Byron R. Kelley	60%
Stephen L. Arata	71%
David G. Marrs	71%
L. Patrick Giroir	67%
Dennie Dixon	53%

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 and before revisions to the Partnership s LTIP.

Table of Contents

Outstanding Equity Awards at December 31, 2009

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

	Option Awards				Stock Awards				
Name	Grant Date	Number of Securities Underlying Unexercised Options Exercisable (#)	Option Exercise Price ($)	Option Expiration Date	Grant Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested[9] ($)	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][9] ($)
Byron R. Kelley					4/01/2008	56,300[2]	1,179,485		
					4/01/2008	37,500[3]	785,625		
					5/27/2009	16,000[4]	349,440	24,000[5]	524,160
Stephen L. Arata	2/03/2006	35,000	20.00	2/03/2016	5/27/2009	8,000[4]	174,720	12,000[5]	262,080
David Marrs					9/01/2009	8,800[4]	188,276	13,200[5]	282,414
L. Patrick Giroir					5/27/2008	7,334[6]	153,647		
					5/27/2008	15,000[7]	314,250		
					5/27/2009	4,000[4]	87,360	6,000[5]	131,040
Dennie Dixon					2/02/2009	15,000[8]	314,250		
					5/27/2009	3,200[4]	69,888	4,800[5]	104,832

(1) The market value of outstanding equity awards was calculated using the closing price of $20.95 on December 31, 2009.

(2) The forfeiture restrictions applicable to these units lapse as to 50 percent of the award on the each of the second and fourth anniversaries of the April 1, 2008 grant date.

(3) The forfeiture restrictions applicable to these units lapse as to 33 percent of the award on each of the second, third and fourth anniversaries of the April 1, 2008 grant date.

(4) The forfeiture restrictions on these time-based phantom unit awards lapse as to 33 percent of the award on each of the first three anniversaries of March 15, 2009.

(5) The forfeiture restrictions on these market-based phantom unit awards lapse on March 15, 2012 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.

(6) The forfeiture restrictions applicable to these units vest as to 50 percent of the award on each of the second and third anniversaries of the May 27, 2008 grant date.

(7) The forfeiture restrictions applicable to these units vest as to 50 percent of the award on May 27, 2010, 25 percent of the award on May 27, 2011, and the remaining 25 percent of the award on May 27, 2012.

(8) The forfeiture restrictions applicable to these units vest as to 25 percent of the award on each of the first four anniversaries of the February 2, 2009 grant date.

99

Table of Contents

(9) 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 ($)	Equity Incentive Plan Awards: Accrued and Unpaid Distributions ($)
Byron R. Kelley	14,240	21,360
Stephen L. Arata	7,120	10,680
David Marrs	3,916	5,874
L. Patrick Giroir	3,560	5,340
Dennie Dixon	2,848	4,272

The following table provides information relating to the vesting of unit awards during 2009 for each of our Named Executive Officers. None of our Named Executive Officers exercised any unit option awards during 2009.

Option Exercises and Stock Vested for the Year Ended December 31, 2009

	Stock Awards	
Name	Number of Shares Acquired on Vesting (#)	Value Realized On Vesting ($)
Byron R. Kelley	12,500	149,125
Stephen L. Arata		
David G. Marrs		
L. Patrick Giroir	3,666	45,678
Dennie Dixon		

Potential Payments upon a Termination or Change in Control

We maintain individual employment and severance agreements with certain of our NEOs that could provide for potential severance payments upon a termination of employment. Our LTIP, subject to alternative provisions provided in individual award agreements, also generally provides for the potential acceleration of all unvested outstanding equity awards upon a change in control.

Employment Agreement with Byron R. Kelley.

The employment agreement we maintain with Mr. Kelley provides that in the event Mr. Kelley is terminated without Cause, or he terminates for Good Reason, we are obligated to provide a lump sum in cash within 10 days of the termination date equal to any earned but unpaid salary and bonus, accrued vacation and unreimbursed expenses (Accrued Obligations). We will also pay him a lump sum within a 60-day period following the date of termination an amount equal to four times his annual base salary. If we decide to waive his non-compete provisions (which extend for two years following a termination of employment), however, we may reduce this severance payment to two times his annual base salary. If we terminate Mr. Kelley without Cause or he terminates for Good Reason three months preceding or within the two-year period immediately following a Change in Control, we will pay Mr. Kelley an amount that is equal to four times his annual base salary, whether or not we have waived his non-compete provisions (whether utilizing the multiplying factor of two or four, such payment will be referred to as the CEO Severance Payment). Mr. Kelley will also receive COBRA continuation coverage at the same monthly premium charged to an active employee for similar coverage during the twelve-month period following such a termination of employment without Cause or for Good Reason. Mr. Kelley will be required to sign a full release before receiving the CEO Severance Payment or the COBRA continuation coverage.

Table of Contents

In the event of Mr. Kelley s termination of employment due to his death or Disability he, or his representatives, will receive the Accrued Obligations in a lump sum within 10 days of the date of termination. If Mr. Kelley begins receiving benefits under our long-term disability plan following a Disability termination, we will provide a monthly payment to Mr. Kelley until he reaches age 65 equaling the difference between the disability payments he receives from such plan, and the disability payments he would have received from the plan if the plan did not limit payments to 60 percent of his annual base salary. In the event Mr. Kelley is terminated for Cause, we shall be obligated to pay him any unpaid Accrued Obligations within 10 days of his termination.

Despite the timing of payments noted above, Mr. Kelley will not receive any payments pursuant to his employment agreement before the first day of the seventh month following his termination from service in the event that he is considered a specified employee pursuant to section 409A of the Code and such a delay is necessary in order to comply with the timing restrictions of section 409A of the Code and its accompanying regulations.

A Good Reason termination may occur upon a material reduction in Mr. Kelley s authority or duties, a reduction in his base salary, our material breach of his employment agreement, or our requirement that he relocate to an office outside of Texas. Mr. Kelley s termination for Cause shall mean: (i) a material nonperformance of his duties; (ii) his commission of fraud upon, or willful misconduct with respect to, us or any of our affiliates; (iii) a material breach of confidentiality, or any breach of the non-compete, non-solicitation or prior commitment provisions within his employment agreement; (iv) a felony conviction or a misdemeanor involving moral turpitude; (v) any conduct of Mr. Kelley that causes us public disgrace or disrepute; or (vi) failure to comply with a directive from our Board of Directors. Disability is defined as Mr. Kelley s inability to perform his duties, with or without reasonable accommodation, due to a mental or physical incapacity for a period of time as defined in our long-term disability plan, and in the event that no such plan exists at the time that Mr. Kelley s Disability must be determined, for a period of 180 consecutive days. A Change in Control under Mr. Kelley s employment agreement will occur only on the date that the GE EFS Group (meaning Regency GP Acquirer L.P., Regency LP Acquirer LP and any person that controls these entities or their respective directors, officers, shareholders, members, employees or management committees) ceases to be the beneficial owner of at least 50 percent of the combined voting power of our outstanding voting securities.

Both during the term of his employment and thereafter, Mr. Kelley may not disclose our confidential information and shall not use such information for his own benefit nor for the benefit of any other party than us. As partial consideration for the payments and benefits provided to him pursuant to his employment agreement, unless waived as described above, Mr. Kelley will remain subject to two year non-competition and non-solicitation restrictions following a termination of his employment with us.

Employment Agreement with David Marrs.

The employment agreement we maintain with David Marrs provides for severance payments in the event that we terminate him without Cause or he terminates his employment for Good Reason. Following his execution of a full and general release in our favor, Mr. Marrs could receive a lump sum payment equal to one year s base salary, a pro-rated bonus payment, continuation of medical coverage for 36 months (the first 18 months being a reimbursement of 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 he experienced during the previous 18 months) or until Mr. Marrs and his dependents are covered by a third-party employer s insurance plans, all outstanding time-vested equity awards other than any Class C units in our General Partner will become vested, and all outstanding performance-based equity awards will vest pro rata.

In the event of Mr. Marrs termination of employment due to the nonrenewal of his employment agreement, his death, or Disability, he, or his representatives, will receive any accrued but unpaid salary in a lump sum within 74 days of the date of his termination. Mr. Marrs outstanding time-vested equity awards other than any

Class C units in our General Partner will become vested, and all outstanding performance-based equity awards will vest pro rata. A termination for Cause or Mr. Marrs resignation without Good Reason will require the forfeiture of all deferred compensation, unused vacation time, unpaid bonuses, and unredeemed or unvested equity awards.

Cash severance payments will be paid to Mr. Marrs within 74 days following his termination of employment, unless he is considered a specified employee pursuant to section 409A of the Code, in which case payments will be delayed for a period of six months following the date of termination.

Good Reason termination events for Mr. Marrs include a material change in Mr. Marrs duties, or our failure to cure a material breach of his employment agreement. Mr. Marrs employment agreement provides for a termination for Cause upon: (a) his conviction of a felony, (b) his breach of the confidentiality or non-compete obligations, (c) his breach of a fiduciary duty of loyalty, due care or good faith, (d) willful or gross neglect of his duties, (e) committing an act of fraud against us or willful misconduct, (f) misappropriating our funds or property, (g) acting in a manner that competes or materially injures us, or (h) his material breach of his employment agreement. A Disability will be determined under the same definition as such term in our then-current long term disability plan.

Both during the term of his employment and thereafter, Mr. Marrs may not disclose our confidential information and shall not use such information for his own benefit nor for the benefit of any other party than us. Mr. Marrs will generally be subject to a non-compete and non-solicitation period of three years following his termination of employment other than for Cause or Good Reason; in the event Mr. Marrs is terminated by us without Cause or he resigns for Good Reason, the term of the non-compete and non-solicitation period shall be one year. We have also entered into a mutual non-disparagement covenant with Mr. Marrs for a period of three years following his termination of employment.

Agreements with Messrs. Arata, Giroir and Dixon.

Messrs. Arata, Giroir and Dixon do not have individual employment agreements that provide for severance or change in control payments. In the event that any of these executives hold equity-based compensation awards upon a termination of their employment or a change in control, they will be subject to the applicable terms and restrictions contained in our LTIP, as described below.

Termination of Employment or Change in Control Under our LTIP.

The restricted units, phantom units and options awarded under the LTIP to our NEOs contain provisions that provide for certain portions of the awards to receive accelerated vesting upon either a Change in Control, or the death or Disability of the executive; in the case of Mr. Kelley, the time-based vesting restricted units granted in 2008 will also receive accelerated vesting upon his resignation for Good Reason, as defined in his employment agreement described above. Generally, the 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 (which for the 2009 grants, is May 27, 2009 through March 15, 2012). The phantom award agreements we have with Messrs. Kelley and Dixon also provide for accelerated pro-rata vesting of their performance-based units upon a normal Retirement, defined to mean a termination of employment on or after reaching age 62 (both Messrs. Kelley and Dixon have reached age 62). Mr. Kelley s performance-based unit agreement further notes that if he terminates for Good Reason his award will continue to vest throughout the remainder of the performance period. The phantom unit agreements we have with Mr. Marrs provide accelerated vesting upon a termination without Cause or upon a Good Reason termination, which is also reflected in his employment agreement described above. Unless an executive s employment agreement states otherwise, all other terminations will require a forfeiture of any unvested restricted units.

A Change in Control is 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

Table of Contents

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; (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.

Potential Payments Upon a Termination or Change in 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, 2009. 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 the equity awards performance period in 2012, but the following are our best estimates as to the amounts that the current NEOs are entitled to as of December 31, 2009, and using our closing stock price on that date of $20.95. 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, 2009.

Executive	Change in Control	Termination of Employment for Death or Disability	Retirement	Termination of Employment Without Cause or for Good Reason
Byron R. Kelley				
CEO Severance Payment[1]	N/A	N/A	N/A	$ 1,957,000
Accelerated Equity[2]	$ 3,054,510	$ 2,387,406	$ 107,096	2,469,910
Continued Medical[3]	N/A	N/A	N/A	9,708
Supplemental Disability Benefits[4]	N/A	$309,240	N/A	N/A
Total	$ 3,054,510	$ 2,696,646	$ 107,096	$ 4,436,618
Stephen L. Arata			N/A	N/A
Accelerated Equity[2][5]	$ 544,700	$ 221,149		
Total	$ 544,700	$ 221,149		
David Marrs			N/A	
Severance Payment[6]	N/A	N/A		$ 502,500
Accelerated Equity[2]	$ 599,170	$ 243,263		243,263[8]
Continued Medical[7]	N/A	N/A		39,960
Total	$ 599,170	$ 243,263		$ 785,723
L. Patrick Giroir			N/A	N/A
Accelerated Equity[2]	$ 586,600	$ 578,471		
Total	$ 586,600	$ 578,471		
Dennie Dixon				N/A
Accelerated Equity[2]	$ 532,130	$ 402,709	$ 21,419	
Total	$ 532,130	$ 402,709	$ 21,419	

(1) This amount was calculated by multiplying Mr. Kelley s base salary ($489,250) by four. We have assumed for purposes of this table that we did not waive the non-compete provisions and will pay the CEO Severance Payment using the maximum multiplier of four, although the amount that he could receive could be reduced by half if we determine to waive such provisions upon his actual termination of employment. This amount also reflects the amount that Mr. Kelley would receive if the termination without Cause or for Good Reason occurred in connection with a Change in Control.

(2) Amounts were calculated by multiplying the number of such units the executive held on December 31, 2009 (16,000 units granted in 2009, along with 93,800 units granted in 2008 for Mr. Kelley; 8,800 units for Mr. Marrs; 8,000 units for Mr. Arata; 26,334 units for Mr. Giroir; and 18,200 units for Mr. Dixon) by our closing stock price of $20.95. Please note that Mr. Kelley s time-based units granted in 2008 will accelerate

upon a termination for Good Reason in the column titled Termination of Employment Without Cause or for Good Reason above, although not upon a termination without Cause. Upon a termination without Cause, Mr. Kelley s Total Accelerated Equity would equal $502,800.

Performance-based Units. In addition, pursuant to the award agreements, we estimated a pro-rata acceleration of performance-based phantom units by multiplying the number of such outstanding units (24,000 units for Mr. Kelley; 13,200 for Mr. Marrs; 12,000 for Mr. Arata; 6,000 for Mr. Giroir; and 4,800 for Mr. Dixon) by a fraction (218/1023, or the number of days which had lapsed in the performance period as of December 31, 2009 over the full number of days in the performance period), and then multiplied this number by $20.95. 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, 2012, 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, 2009 stock price. A termination for Good Reason, although not upon a termination without Cause, for Mr. Kelley requires continued vesting during the performance period rather than pro-rata, thus the calculation above for his accelerated equity assumes the number of performance-based units he held on December 31, 2009 will continue to vest, although for purposes of provided an estimated value of these awards we have used our December 31, 2009 stock price. For a Change in Control during the performance period, however, all executives would be considered automatically vested at Maximum at the time of such a Change in Control at a rate of 150 percent for the performance-based units, thus the amounts attributable to the performance-based units in the Change in Control column above are multiplied by 150 percent.

(3) This amount was calculated by multiplying the monthly COBRA premium amount of $809 over the period of 12 months.

(4) As of December 31, 2009, our long-term disability plan would cap monthly benefits at $15,000, leaving a remaining balance of $25,770 per month. Mr. Kelley would receive this supplemental payment until he reaches the age of 65, and so the amount reflected here was calculated my multiplying $25,770 by 20 months.

(5) Mr. Arata holds 35,000 option awards with an exercise price of $20.00 per share. While these options have not yet been exercised, the options are vested and Mr. Arata is currently entitled to exercise the options, thus the amounts reflected in Mr. Arata s Accelerated Equity line above disclose only the value of his phantom units that would receive accelerated vesting upon the applicable termination scenario or a change in control.

(6) This amount was calculated by aggregating Mr. Marrs base salary for the 2009 year ($300,000) with a pro-rata bonus for the 2009 year (which, because a hypothetical termination is assumed as of December 31, 2009, would be the full bonus Mr. Marrs received for the 2009 year ($202,500)).

(7) This amount was calculated by combining 18 months of COBRA premiums for Mr. Marrs and his dependents at a rate of $1,110 18 per month with 18 months of reimbursement payments for continued health benefits (which, as this benefit may not exceed the monthly COBRA premium costs for the first 18 months, will be assumed to be equal to the COBRA premium costs for the period). The number shown above may be higher than the actual amount paid to Mr. Marrs due to the fact that continued health benefits will cease if Mr. Marrs becomes covered under a third party employer s health plan.

(8) In addition to a without Cause and a Good Reason termination, Mr. Marrs performance-based phantom unit agreement also provides for the pro-rata acceleration of his awards upon the natural expiration of his employment agreement term without renewal. Using the methods noted in footnote 2 above, Mr. Marrs would have received $58,903 if his employment agreement term had expired on December 31, 2009. Mr. Marrs time-based unit agreements do not contain this provision.

Table of Contents

Directors Compensation

The directors of the General Partner who are not employees of the General Partner received in 2009 an annual retainer of $30,000, a flat fee of $1,000 for each meeting of the board and $500 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, Mr. John Mills receives $7,500 annually as compensation for his role as chairman of the Audit Committee. These amounts are determined on an annual basis by our Board.

Director Compensation for 2009

The following table presents the cash, equity awards and other compensation earned, paid or awarded to each of our directors during the year ended December 31, 2009.

Name	Fees Earned or Paid	Total ($)
Michael J. Bradley	44,000	44,000
James F. Burgoyne(1)	35,000	35,000
Daniel R. Castagnola(1)	34,500	34,500
Rodney L. Gray	42,500	42,500
Paul J. Halas(1)	35,500	35,500
Mark T. Mellana(1)	38,000	38,000
John T. Mills	52,000	52,000
Brian P. Ward(1)	33,000	33,000

(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.

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

The following table sets forth, as of February 23, 2010, 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;
- each named executive officer of Regency GP LLC; and
- all directors and executive officers of Regency GP LLC, as a group.

Table of Contents

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 Owner	Business Address	Common Units	Percentage of Outstanding Common Units
Aircraft Services Corp	800 Long Ridge Rd. Stamford, CT 06927	24,679,577	26.5%
Kayne Anderson Capital Advisors, L.P.	1800 Avenue of the Stars, Second Floor Los Angeles, CA 90067	8,486,986	9.1%
Neuberger Berman Group LLC	605 Third Avenue New York, NY 10158	7,167,469	7.7%
Byron R. Kelley		55,233	*
Stephen L. Arata		209,171	0.2%
David G. Marrs		309,655	0.3%
L. Patrick Giroir		1,333	*
Dennie M. Dixon		4,817	*
Michael T. Bradley		2,500	*
James F. Burgoyne			*
Daniel R. Castagnola			*
Rodney Gray		2,500	*
Paul J. Halas			*
Mark T. Mellana			*
John T. Mills		7,500	*
Brian P. Ward			*
All directors and executive officers as a group (15 persons)		689,720	0.7%
Total number of units as of February 23, 2010		93,174,103	

Securities Authorized for Issuance under Equity Compensation Plans. The following table provides information concerning common units that may be issued under the General Partner LTIP. The LTIP consists of restricted units, phantom units and unit options. It currently permits the grant of awards covering an aggregate of 2,865,584 units. The LTIP is administered by the Compensation Committee of the Board of Directors of our General Partner.

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.

Table of Contents

The following table summarizes the number of securities remaining available for future issuance under the LTIP plan as of December 31, 2009.

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 Compensation 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)]	306,651	21.50	442,231
Total	306,651	$ 21.50	442,231

(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 2,865,584 units, which grant did not require approval by our limited partners.

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

Further information required for this item is provided in Item 1 Business Overview, Item 10 Directors, Executive Officers and Corporate Governance and Note 14, Related Party Transactions, included in the notes to the audited consolidated financial statements included in Item 8 Financial Statements and Supplementary Data.

Item 14. Principal Accounting 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, 2009 and 2008.

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, 2009 and 2008.

	December 31, 2009	December 31, 2008
	(in thousands)	
Audit fees[(1)]	$ 1,940	$ 1,732
Audit related fees[(2)]	68	31
Tax fees[(3)]		10
Total	$ 2,008	$ 1,773

(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.

(3) Includes fees related to professional services for tax compliance, tax advice and tax planning.

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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/ BYRON R. KELLEY
Byron R. Kelley
Chairman of the Board, 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/ BYRON R. KELLEY **Byron R. Kelley**	Chairman of the Board, President, and Chief Executive Officer (Principal Executive Officer)	March 1, 2010
/s/ STEPHEN L. ARATA **Stephen L. Arata**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2010
/s/ LAWRENCE B. CONNORS **Lawrence B. Connors**	Senior Vice President, Finance and Accounting (Principal Accounting Officer)	March 1, 2010
/s/ MICHAEL J. BRADLEY **Michael J. Bradley**	Director	March 1, 2010
/s/ JAMES F. BURGOYNE **James F. Burgoyne**	Director	March 1, 2010
/s/ DANIEL R. CASTAGNOLA **Daniel R. Castagnola**	Director	March 1, 2010
/s/ RODNEY L. GRAY **Rodney L. Gray**	Director	March 1, 2010
/s/ PAUL J. HALAS **Paul J. Halas**	Director	March 1, 2010

/s/ MARK T. MELLANA	Director	March 1, 2010
Mark T. Mellana		
/s/ JOHN T. MILLS	Director	March 1, 2010
John T. Mills		
/s/ BRIAN P. WARD	Director	March 1, 2010
Brian P. Ward		

Table of Contents

Index to Exhibits

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
2.1	Contribution Agreement by and among Regency Energy Partners LP, Regency Gas Services LP, as Buyer and HMTF Gas Partners II, L.P., as Seller dated July 12, 2006	8-K	August 14, 2006
2.2	Stock Purchase Agreement by and among Regency Energy Partners LP, Pueblo Holdings, Inc., as Buyer, Bear Cub Investments, LLC, the Members of Bear Cub Investments, LLC identified herein, as Sellers, and Robert J. Clark, as Sellers Representative dated April 2, 2007	8-K	April 3, 2007
2.3	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
2.4	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
2.5	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
2.6	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

Table of Contents

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
3.2.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	August 28, 2008
3.2.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	February 27, 2009
3.2.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	September 4, 2009
3.3	Certificate of Formation of Regency GP LLC	S-1	333-128332
3.4	Form of Amended and Restated Limited Liability Company Agreement of Regency GP LLC	S-1	333-128332
3.5	First Amendment to Amended and Restated Limited Liability Company Agreement of Regency GP LLC		
3.6	Certificate of Limited Partnership of Regency GP LP	S-1	333-128332
3.7	Form of Amended and Restated Limited Partnership Agreement of Regency GP LP	S-1	333-128332
3.8	Second Amended and Restated General Partnership Agreement of RIGS Haynesville Partnership Co. dated as of December 18, 2009		
4.1	Form of Common Unit Certificate	S-1	333-128332
4.2	Indenture for 8 $^{3}/8$ percent Senior Notes due 2013, together with the global notes	10-K	March 30, 2007
4.3	Indenture for 9 $^{3}/8$ percent Senior Notes due 2016, together with the global notes	10-Q	August 10, 2009
4.4	Registration Rights Agreement for 9 $^{3}/8$ percent Senior Notes due 2016	10-Q	August 10, 2009
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 March 17, 2008 between the Registrant and Byron R. Kelley	10-K	March 2, 2009
10.8	Severance Agreement with Dan A. Fleckman	10-Q	March 31, 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

Table of Contents

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
10.12	Amended and Restated Credit Agreement of Regency Gas Services LLC dated as of December 1, 2004, and amended and restated as of July 26, 2005	S-1	333-128332
10.13	Amended and Restated Second Lien Credit Agreement of Regency Gas Services LLC dated as of December 1, 2004, and amended and restated as of July 26, 2005	S-1	333-128332
10.14	Second Amended and Restated Credit Agreement of Regency Gas Services LLC dated as of December 1, 2004, and amended and restated as of July 26, 2005 and November 30, 2005	S-1	333-128332
10.15	Form of Third Amended and Restated Credit Agreement of Regency Gas Services LLC	S-1	333-128332
10.16	Fourth Amended and Restated Credit Agreement dated as of December 1, 2004, as amended, among Regency Gas Services LP, Regency Energy Partners LP, the other guarantors named therein, Wachovia Bank, National Association, UBS Securities LLC and the other lenders named therein	8-K	August 15, 2006
10.17	Amendment and Waiver Agreement No. 2 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated June 29, 2007	8-K	July 3, 2007
10.18	Amendment Agreement No. 3 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated September 28, 2007	8-K	October 3, 2007
10.19	Amendment Agreement No. 4 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated January 15, 2008	8-K	February 12, 2008
10.20	Amendment Agreement No. 5 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP and Amendment No.1 to Security Agreement dated February 13, 2008	8-K	February 19, 2008
10.21	Amendment Agreement No. 6 and Waiver with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated May 9, 2008	8-K	October 16, 2008
10.22	Amendment Agreement No. 7 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated as of February 26, 2009	8-K	March 18, 2009
10.23	Amendment Agreement No. 8 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated July 24, 2009	8-K	July 24, 2009
10.24	Master Lease Agreement between Caterpillar Financial Services Corporation and CDM Resource Management LLC, dated as of February 26, 2009	10-K	March 2, 2009
10.25	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	July 24, 2009

Table of Contents

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
10.26	Revolving Credit Agreement dated as of February 26, 2009 of Regency Energy Partners LP	10-K	March 2, 2009
10.27	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		
10.28	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
10.29	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
10.30	Series A Cumulative Convertible Preferred Unit Purchase Agreement, dated September 2, 2009, by and among Regency Energy Partners LP and the purchasers named therein	8-K	September 4, 2009
10.31	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
10.32	Consulting Agreement with Randall Dean dated as of September 1, 2009	10-Q	November 9, 2009
10.33	Employment Agreement with David Marrs dated as of September 1, 2009	10-Q	November 9, 2009
10.34	Severance Agreement with Paul Jolas dated as of September 8, 2009	10-Q	November 9, 2009
12.1	Computation of Ratio of Earnings to Fixed Charges		
14.1	Code of Business Conduct	10-K	March 30, 2007
21.1	List of Subsidiaries of Regency Energy Partners LP		
23.1	Consent of KPMG LLP		
24.1^	Form by Power of Attorney		
31.1	Certifications pursuant to Rule13a-14(a).		
31.2	Certifications pursuant to Rule13a-14(a).		
32.1	Certifications pursuant to Section 1350.		
32.2	Certifications pursuant to Section 1350.		
99.1	Regency GP LP December 31, 2009 Consolidated Balance Sheet		

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
99.2	Regency Energy Partners LP Notice of Beginning of Administrative Proceeding for Tax Year Ended December 31, 2008		
99.3	Regency Energy Partners LP Notice of Beginning of Administrative Proceeding for Tax Year Ended December 31, 2007		

^ Incorporated by reference to the signature page of this filing.

Index to Consolidated Financial Statements

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, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners capital and noncontrolling interest for each of the years in the three-year period ended December 31, 2009. 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 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, 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, 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, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2010 expressed an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas

March 1, 2010

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, 2009, 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, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners capital and noncontrolling interest for each of the years in the three-year period ended December 31, 2009, and our report dated March 1, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas

March 1, 2010

Table of Contents

Regency Energy Partners LP

Consolidated Balance Sheets

(in thousands except unit data)

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,827	$ 599
Restricted cash	1,511	10,031
Trade accounts receivable, net of allowance of $1,130 and $941	30,433	40,875
Accrued revenues	95,240	96,712
Related party receivables	6,222	855
Derivative assets	24,987	73,993
Other current assets	10,556	13,338
Total current assets	178,776	236,403
Property, Plant and Equipment:		
Gathering and transmission systems	465,959	652,267
Compression equipment	823,060	799,527
Gas plants and buildings	159,596	156,246
Other property, plant and equipment	162,433	167,256
Construction-in-progress	95,547	154,852
Total property, plant and equipment	1,706,595	1,930,148
Less accumulated depreciation	(250,160)	(226,594)
Property, plant and equipment, net	1,456,435	1,703,554
Other Assets:		
Investment in unconsolidated subsidiary	453,120	
Long-term derivative assets	207	36,798
Other, net of accumulated amortization of debt issuance costs of $10,743 and $5,246	19,468	13,880
Total other assets	472,795	50,678
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $33,929 and $22,517	197,294	205,646
Goodwill	228,114	262,358
Total intangible assets and goodwill	425,408	468,004
TOTAL ASSETS	$ 2,533,414	$ 2,458,639
LIABILITIES & PARTNERS CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 44,912	$ 65,483
Accrued cost of gas and liquids	76,657	76,599
Related party payables	2,312	
Deferred revenue, including related party amounts of $338 and $0	11,292	11,572
Derivative liabilities	12,256	42,691
Escrow payable	1,511	10,031
Other current liabilities	12,368	10,574
Total current liabilities	161,308	216,950
Long-term derivative liabilities	48,903	560

Other long-term liabilities	14,183	15,487
Long-term debt, net	1,014,299	1,126,229
Commitments and contingencies		
Series A convertible redeemable preferred units, redemption amount $83,891	51,711	
Partners Capital and Noncontrolling Interest:		
Common units (94,243,886 and 55,519,903 units authorized; 93,188,353 and 54,796,701 units issued and outstanding at December 31, 2009 and 2008)	1,211,605	764,161
Class D common units (7,276,506 units authorized, issued and outstanding at December 31, 2008)		226,759
Subordinated units (19,103,896 units authorized, issued and outstanding at December 31, 2008)		(1,391)
General partner interest	19,249	29,283
Accumulated other comprehensive (loss) income	(1,994)	67,440
Noncontrolling interest	14,150	13,161
Total partners capital and noncontrolling interest	1,243,010	1,099,413
TOTAL LIABILITIES AND PARTNERS CAPITAL AND NONCONTROLLING INTEREST	$ 2,533,414	$ 2,458,639

See accompanying notes to consolidated financial statements

F-4

Table of Contents

Regency Energy Partners LP

Consolidated Statements of Operations

(in thousands except unit data and per unit data)

	Year Ended December 31, 2009	2008	2007
REVENUES			
Gas sales	$ 481,400	$ 1,126,760	$ 744,681
NGL sales	262,652	409,476	347,737
Gathering, transportation and other fees, including related party amounts of $11,162, $3,763 and $1,350	273,770	286,507	100,644
Net realized and unrealized gain (loss) from derivatives	41,577	(21,233)	(34,266)
Other	30,098	62,294	31,442
Total revenues	1,089,497	1,863,804	1,190,238
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $10,913, $1,878 and $14,165 and excluding items shown separately below	699,563	1,408,333	976,145
Operation and maintenance	130,826	131,629	58,000
General and administrative	57,863	51,323	39,713
Loss (gain) on asset sales, net	(133,284)	472	1,522
Management services termination fee		3,888	
Transaction expenses		1,620	420
Depreciation and amortization	109,893	102,566	55,074
Total operating costs and expenses	864,861	1,699,831	1,130,874
OPERATING INCOME	224,636	163,973	59,364
Income from unconsolidated subsidiary	7,886		
Interest expense, net	(77,996)	(63,243)	(52,016)
Loss on debt refinancing			(21,200)
Other income and deductions, net	(15,132)	332	1,252
INCOME (LOSS) BEFORE INCOME TAXES	139,394	101,062	(12,600)
Income tax (benefit) expense	(1,095)	(266)	931
NET INCOME (LOSS)	$ 140,489	$ 101,328	$ (13,531)
Net income attributable to noncontrolling interest	(91)	(312)	(305)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ 140,398	$ 101,016	$ (13,836)
Amounts attributable to Series A convertible redeemable preferred units	3,995		
General partner's interest, including IDR	5,252	4,303	(366)
Amount allocated to non-vested common units	965	869	(103)
Beneficial conversion feature for Class D common units	820	7,199	
Beneficial conversion feature for Class C common units			1,385
Amount allocated to Class E common units			5,792
Limited partners' interest	$ 129,366	$ 88,645	$ (20,544)
Basic and Diluted earnings (loss) per unit:			
Amount allocated to common and subordinated units	$ 129,366	$ 88,645	$ (20,544)
Weighted average number of common and subordinated units outstanding	80,582,705	66,190,626	51,056,769
Basic income (loss) per common and subordinated unit	$ 1.61	$ 1.34	$ (0.40)
Diluted income (loss) per common and subordinated unit	$ 1.60	$ 1.28	$ (0.40)
Distributions paid per unit	$ 1.78	$ 1.71	$ 1.52

Amount allocated to Class B common units	$	$	$
Weighted average number of Class B common units outstanding			651,964
Income per Class B common unit	$	$	$
Distributions per unit	$	$	$
Amount allocated to Class C common units	$	$	$ 1,385
Total number of Class C common units outstanding			2,857,143
Income per Class C common unit due to beneficial conversion feature	$	$	$ 0.48
Distributions per unit	$	$	$
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 per unit	$	$	$
Amount allocated to Class E common units	$	$	$ 5,792
Total number of Class E common units outstanding			4,701,034
Income per Class E common unit due to beneficial conversion feature	$	$	$ 1.23
Distributions per unit	$	$	$ 2.06

See accompanying notes to consolidated financial statements

F-5

Table of Contents

Regency Energy Partners LP

Consolidated Statements of Comprehensive Income (Loss)

(in thousands)

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$ 140,489	$ 101,328	$ (13,531)
Net hedging amounts reclassified to earnings	(47,394)	35,512	19,362
Net change in fair value of cash flow hedges	(22,040)	70,253	(58,706)
Comprehensive income (loss)	$ 71,055	$ 207,093	$ (52,875)
Comprehensive income attributable to noncontrolling interest	91	312	305
Comprehensive income (loss) attributable to Regency Energy Partners LP	$ 70,964	$ 206,781	$ (53,180)

See accompanying notes to consolidated financial statements

Table of Contents

Regency Energy Partners LP

Consolidated Statements of Cash Flows

(in thousands)

	Year Ended December 31,		
	2009	**2008**	**2007**
OPERATING ACTIVITIES			
Net income	$ 140,489	$ 101,328	$ (13,531)
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization	116,307	105,324	57,069
Write-off of debt issuance costs			5,078
Non-cash income from unconsolidated subsidiary			(43)
Derivative valuation changes	5,163	(14,700)	14,667
Loss (gain) on asset sales, net	(133,284)	472	1,522
Unit based compensation expenses	6,008	4,306	15,534
Gain on insurance settlements		(3,282)	
Cash flow changes in current assets and liabilities:			
Trade accounts receivable, accrued revenues, and related party receivables	10,727	18,648	(28,789)
Other current assets	10,471	(6,615)	(1,394)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(3,762)	(40,772)	30,089
Other current liabilities	(6,726)	12,749	(149)
Amount of swap termination proceeds reclassified into earnings			(1,078)
Other assets and liabilities	(1,433)	3,840	554
Net cash flows provided by operating activities	143,960	181,298	79,529
INVESTING ACTIVITIES			
Capital expenditures	(193,083)	(375,083)	(129,784)
Acquisitions	(52,803)	(577,668)	(34,855)
Return of investment in unconsolidated subsidiary	1,039		
Acquisition of investment in unconsolidated subsidiary, net of $100 cash			(5,000)
Net proceeds from asset sales	88,682	840	11,706
Proceeds from insurance settlement		3,282	
Net cash flows used in investing activities	(156,165)	(948,629)	(157,933)
FINANCING ACTIVITIES			
Net (repayments) borrowings under revolving credit facilities	(349,087)	644,729	59,300
Repayments under credit facilities			(50,000)
Proceeds from issuance (repayments) of senior notes, net of discount	236,240		(192,500)
Debt issuance costs	(12,224)	(2,940)	(2,427)
Partner contributions	6,344	11,746	7,735
Partner distributions	(146,585)	(120,591)	(79,933)
Acquisition of assets between entities under common control in excess of historical cost	(10,197)		
Proceeds from option exercises		2,700	
Proceeds from equity issuances, net of issuance costs	220,318	199,315	353,546
Proceeds from preferred equity issuance, net of issuance costs	76,624		
FrontStreet distributions			(9,695)
FrontStreet contributions			13,417
Net cash flows provided by financing activities	21,433	734,959	99,443
Net increase (decrease) in cash and cash equivalents	9,228	(32,372)	21,039
Cash and cash equivalents at beginning of period	599	32,971	9,139
Cash acquired from FrontStreet			2,793
Cash and cash equivalents at end of period	$ 9,827	$ 599	$ 32,971

Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 69,401	$ 59,969	$ 67,844
Income taxes paid	6	605	
Non-cash capital expenditures in accounts payable	9,688	25,845	7,761
Non-cash capital expenditure for consolidation of investment in previously unconsolidated subsidiary			5,650
Non-cash capital expenditure upon entering into a capital lease obligation			3,000
Issuance of common units for an acquisition		219,560	19,724
Release of escrow payable from restricted cash	8,501	4,570	
Contribution of fixed assets, goodwill and working capital to HPC	263,921		
Non-cash proceeds from contribution of RIGS 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

Table of Contents

Regency Energy Partners LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest

(in thousands except unit data)

	Units						Common	Class B
	Common	**Class B**	**Class C**	**Class D**	**Class E**	**Subordinated**	**Unitholders**	**Unitholders**
Balance December 31, 2006	19,620,396	5,173,189	2,857,143			19,103,896	$ 42,192	$ 60,671
Conversion of Class B and C to common units	8,030,332	(5,173,189)	(2,857,143)				120,663	(60,671)
Issuance of common units for acquisition	751,597						19,724	
Issuance of common units	11,500,000						353,446	
Issuance of restricted common units, net of forfeitures	565,167							
Exercise of common unit options	47,403						100	
Unit based compensation expenses							15,534	
Partner distributions							(49,296)	
Partner contributions								
Acquisition of FrontStreet					4,701,034			
FrontStreet contributions								
FrontStreet distributions								
Contributions from noncontrolling interest								
Net (loss) income							(12,037)	
Other							25	
Net hedging activity reclassified to earnings								
Net change in fair value of cash flow hedges								
Balance December 31, 2007	40,514,895				4,701,034	19,103,896	490,351	
Issuance of Class D common units				7,276,506				
Issuance of restricted common units and option exercises, net of forfeitures	559,863						2,700	
Issuance of common units	9,020,909						199,315	
Working capital adjustment on FrontStreet								
Acquisition on noncontrolling interest								
Conversion of Class E common units	4,701,034				(4,701,034)		92,104	
Unit based compensation expenses							4,306	
Partner distributions							(84,207)	
Partner contributions								
Net income							59,592	
Contributions from noncontrolling interest								
Net hedging amounts reclassified to earnings								
Net change in fair value of cash flow hedges								
Balance December 31, 2008	54,796,701			7,276,506		19,103,896	764,161	
Revision of partner interest							6,073	
Issuance of restricted common units, net of forfeitures	(63,750)							
Issuance of common units	12,075,000						220,318	
Conversion of subordinated units	19,103,896					(19,103,896)	(1,391)	
Unit based compensation expenses							6,008	
Accrued distributions to phantom units							(249)	
Acquisition of assets between entities under common control in excess of historical cost								
Partner distributions							(141,225)	

Partner contributions				
Net income			134,326	
Conversion of Class D common units	7,276,506	(7,276,506)	227,579	
Contributions from noncontrolling interest				
Accrued distributions to Series A convertible redeemable preferred units			(3,891)	
Accretion of Series A convertible redeemable preferred units			(104)	
Net cash flow hedge amounts reclassified to earnings				
Net change in fair value of cash flow hedges				
Balance December 31, 2009	93,188,353		$ 1,211,605	$

See accompanying notes to consolidated financial statements

Table of Contents

Regency Energy Partners LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest (Continued)

(in thousands except unit data)

	Class C Unitholders	Class D Unitholders	Class E Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance December 31, 2006	$ 59,992	$	$	$ 43,240	$ 5,543	$ 1,019	$	$ 212,657
Conversion of Class B and C to common units	(59,992)							
Issuance of common units for acquisition								19,724
Issuance of common units								353,446
Issuance of restricted common units, net of forfeitures								
Exercise of common unit options								100
Unit based compensation expenses								15,534
Partner distributions				(29,038)	(1,599)			(79,933)
Partner contributions					7,735			7,735
Acquisition of FrontStreet			83,448					83,448
FrontStreet contributions			13,417					13,417
FrontStreet distributions			(9,695)					(9,695)
Contributions from noncontrolling interest							4,588	4,588
Net (loss) income			5,792	(7,198)	(393)		305	(13,531)
Other				15				40
Net hedging activity reclassified to earnings						19,362		19,362
Net change in fair value of cash flow hedges						(58,706)		(58,706)
Balance December 31, 2007			92,962	7,019	11,286	(38,325)	4,893	568,186
Issuance of Class D common units		219,560						219,560
Issuance of restricted common units and option exercises, net of forfeitures								2,700
Issuance of common units								199,315
Working capital adjustment on FrontStreet			(858)					(858)
Acquisition on noncontrolling interest							(4,893)	(4,893)
Conversion of Class E common units			(92,104)					
Unit based compensation expenses								4,306
Partner distributions				(32,668)	(3,716)			(120,591)
Partner contributions					11,746			11,746
Net income		7,199		24,258	9,967		312	101,328
Contributions from noncontrolling interest							12,849	12,849
Net hedging 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		226,759		(1,391)	29,283	67,440	13,161	1,099,413
Revision of partner interest					(6,073)			

Issuance of restricted common units, net of forfeitures								
Issuance of common units								220,318
Conversion of subordinated units				1,391				
Unit based compensation expenses								6,008
Accrued distributions to phantom units								(249)
Acquisition of assets between entities under common control in excess of historical cost					(10,197)			(10,197)
Partner distributions					(5,360)			(146,585)
Partner contributions					6,344			6,344
Net income		820			5,252		91	140,489
Conversion of Class D common units		(227,579)						
Contributions from noncontrolling interest							898	898
Accrued distributions to Series A convertible redeemable preferred units								(3,891)
Accretion of Series A convertible redeemable preferred units								(104)
Net cash flow hedge amounts reclassified to earnings						(47,394)		(47,394)
Net change in fair value of cash flow hedges						(22,040)		(22,040)
Balance December 31, 2009	$	$	$	$	$ 19,249	$ (1,994)	$ 14,150	$ 1,243,010

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Notes to Consolidated Financial Statements

For the Year Ended December 31, 2009

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 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.

On June 18, 2007, indirect subsidiaries of GECC acquired 91.3 percent of both the member interest in the General Partner and the outstanding limited partner interests in the General Partner from an affiliate of HM Capital Partners and acquired 17,763,809 of the outstanding subordinated units, exclusive of 1,222,717 subordinated units which were owned directly or indirectly by certain members of the Partnership s management. The Partnership was not required to record any adjustments to reflect the acquisition of the HM Capital Partners interest in the Partnership or the related transactions (together, referred to as GE EFS Acquisition).

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 RIGS to a HPC in exchange for a noncontrolling interest in that joint venture. Accordingly, the Partnership no longer consolidates RIGS 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.

Basis of presentation. The consolidated financial statements of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions.

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.

Table of Contents

Restricted Cash. Restricted cash of $1,511,000 is held in escrow for purchase indemnifications related to the El Paso acquisition and for environmental remediation projects. A third-party agent invests funds held in escrow in US Treasury securities. Interest earned on the investment is credited to the escrow account.

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.

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. Sales or retirements of assets, along with the related accumulated depreciation, are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2009, 2008, and 2007, the Partnership capitalized interest of $1,722,000, $2,409,000 and $1,754,000, 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 $97,426,000, $88,828,000, and $50,719,000 for the years ended December 31, 2009, 2008, and 2007, 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. Intangible assets consisting of (i) permits and licenses, (ii) customer contracts, (iii) trade name, and (iv) customer relations 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 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 2009, 2008 or 2007.

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. No impairment was indicated for the years ended December 31, 2009, 2008, or 2007.

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, 2009 and 2008 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, and (iii) contract compression 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 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 on a net basis 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 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. The amount of matching contributions for the years ended December 31, 2009, 2008, and 2007 were $1,440,000, $395,000, and $469,000, 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 wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method for these entities. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership s deferred tax liability of $6,996,000 and $8,156,000 as of December 31, 2009 and 2008 relates 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, 2009 and 2008. The Partnership s entities that are required to pay federal income tax recognized current federal income tax benefit of $420,000 and deferred income tax benefit of $1,160,000 using a 35 percent effective rate during the year ended December 31, 2009.

As of December 31, 2009, the IRS is conducting an audit to 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, on January 27, 2010, the IRS mailed two Notice of Beginning of Administrative Proceeding to the Partnership stating that the IRS is commencing audits of the Partnership s 2007 and 2008 partnership tax returns.

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 Convertible Redeemable Preferred Units (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 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 incentive distribution rights (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 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 is 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 is effective for annual reporting periods that begin after November 15, 2009, and for interim periods within that first annual reporting period. The Partnership has evaluated this guidance and determined that it will have no impact on its financial position, results of operations or cash flows as a result of adopting this guidance 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 has evaluated this guidance and determined that it will have no impact on its financial position, results of operations or cash flows upon adopting this guidance.

3. Partners Capital and Distributions

Common Unit Offerings. 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. 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.

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 of 1933, as amended 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 of 1933, as amended 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 1,901,803 equivalent units as of December 31, 2009. 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 incentive distribution rights held by the General Partner entitles it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner s incentive distribution rights 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 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 for that quarter;
- third, 85 percent to all unitholders, pro rata, 13 percent to holders of the incentive distribution rights, 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 incentive distribution rights, 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 incentive distribution rights, and 2 percent to the General Partner.

Table of Contents

Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2009 and 2008:

Distribution Date	Cash Distribution (per Unit)
November 13, 2009	$ 0.445
August 14, 2009	0.445
May 14, 2009	0.445
February 13, 2009	0.445
November 14, 2008	0.445
August 14, 2008	0.445
May 14, 2008	0.420
February 14, 2008	0.400

4. Income (Loss) 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 Earnings per Unit						
Limited partners' interests	$ 129,366	80,582,705	$ 1.61	$ 88,645	66,190,626	$ 1.34
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	$ 130,186	81,480,894	$ 1.60	$ 95,844	74,823,335	$ 1.28

For the year ended December 31, 2007, diluted earnings per unit equals basic because all instruments were antidilutive.

In connection with the CDM acquisition discussed below, 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.

Table of Contents

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.

	For the Year Ended December 31,		
	2009	2008	2007
Restricted (non-vested) common units	566,493		397,500
Common unit options	357,489		738,668
Convertible redeemable preferred units	1,449,211		

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

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 Regency Intrastate Gas System, with a fair value of $401,356,000, to HPC, in exchange for a 38 percent 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 and a 50 percent 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 interest to its fair value), net of transaction costs of $5,530,000.

In September 2009, the Partnership purchased a five percent interest in HPC from EFS Haynesville for $63,000,000, increasing the Partnership s 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.

Table of Contents

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.

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

Table of Contents

2007

Palafox Joint Venture. The Partnership acquired the outstanding interest in the Palafox Joint Venture not owned (50 percent) for $5,000,000 effective February 1, 2007. The Partnership allocated $10,057,000 to gathering and transmission systems in the three months ended March 31, 2007. The allocated amount consists of the investment in unconsolidated subsidiary of $5,650,000 immediately prior to the Partnership s acquisition and the Partnership s $5,000,000 purchase of the remaining interest offset by $593,000 of working capital accounts acquired.

Significant Asset Dispositions. The Partnership sold selected non-core pipelines, related rights of way and contracts located in south Texas for $5,340,000 on March 31, 2007 and recorded a loss on sale of $1,808,000. Additionally, the Partnership sold two small gathering systems and associated contracts located in the Mid-continent region for $1,750,000 on May 31, 2007 and recorded a loss on the sale of $469,000. The Partnership also sold its 34 mile NGL pipeline located in east Texas for $3,000,000 on June 29, 2007 and simultaneously entered into transportation and operating agreements with the buyer. The Partnership accounted for this transaction as a sale-leaseback whereby the $3,000,000 gain was deferred and will be amortized to earnings over a 20 year period. The Partnership recorded $3,000,000 in gathering and transmission systems and the related obligations under capital lease. On August 31, 2007, the Partnership sold an idle processing plant for $1,300,000 and recorded a $740,000 gain.

Acquisition of Pueblo Midstream Gas Corporation. In April 2007, the Partnership and its indirect wholly-owned subsidiary, Pueblo Holdings, acquired all the outstanding equity of Pueblo. The purchase price for the Pueblo acquisition consisted of (1) the issuance of 751,597 common units of the Partnership to the members, valued at $19,724,000 and (2) the payment of $34,855,000 in cash, exclusive of outstanding Pueblo liabilities of $9,822,000 and certain working capital amounts acquired of $108,000. The cash portion of the consideration was financed out of the proceeds of the Partnership s credit facility.

The Pueblo acquisition offered the opportunity to reroute gas to one of the Partnership s existing gas processing plants to provide cost savings. The total purchase price was allocated as follows based on estimates of the fair values of assets acquired and liabilities assumed.

	At April 2, 2007 (in thousands)
Current assets	$ 1,295
Gas plants and buildings	8,994
Gathering and transmission systems	13,079
Other property, plant and equipment	180
Intangible assets subject to amortization (contracts)	5,242
Goodwill	36,523
Assets acquired	65,313
Current liabilities	(1,187)
Long-term liabilities	(9,492)
Total Purchase price	$ 54,634

Table of Contents

The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM, Nexus and Pueblo, as well as the contribution of RIG to HPC as well as the acquisition of additional five percent HPC interest had occurred as of the beginning of the earliest period presented. Such unaudited pro forma financial information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the date referred to above or the results of operations that may be expected in the future.

	Pro Forma Results for the Year Ended December 31,		
	2009	**2008**	**2007**
	(in thousands except unit and per unit data)		
Revenue	$ 1,077,524	$ 1,822,722	$ 1,274,829
Net income attributable to Regency Energy Partners LP	5,844	81,691	112,474
Less:			
Amounts attributable to Series A Convertible Redeemable Preferred Units	7,781	7,781	7,781
General partner's interest, including IDR	2,485	3,769	1,980
Amount allocated to non-vested common units	(266)	491	669
Beneficial conversion feature for Class C common units			1,385
Beneficial conversion feature for Class D common units	820	7,199	
Amount allocated to Class E common units			5,792
Limited partners' interest	$ (4,976)	$ 62,451	$ 94,867
Basic and Diluted earnings per unit:			
Amount allocated to common and subordinated units	$ (4,976)	$ 62,451	$ 94,867
Weighted average number of common and subordinated units outstanding	80,582,705	66,190,626	51,056,769
Basic (loss) income per common and subordinated unit	$ (0.06)	$ 0.94	$ 1.86
Diluted (loss) income per common and subordinated unit	$ (0.06)	$ 0.94	$ 1.59
Distributions paid per unit	$ 1.78	$ 1.71	$ 1.52
Amount allocated to Class B common units	$	$	$
Weighted average number of Class B common units outstanding			651,964
Income per Class B common unit	$	$	$
Distributions per unit	$	$	$
Amount allocated to Class C common units	$	$	$ 1,385
Total number of Class C common units outstanding			2,857,143
Income per Class C common unit due to beneficial conversion feature	$	$	$ 0.48
Distributions per unit	$	$	$
Amount allocated to Class D common units	$ 820	$ 7,199	$
Total number of Class D common units outstanding	7,276,506	7,276,506	7,276,506
Income per Class D common unit due to beneficial conversion feature	$ 0.11	$ 0.99	$
Distributions per unit	$	$	$
Amount allocated to Class E common units	$	$	$ 5,792
Total number of Class E common units outstanding			4,701,034
Income per Class E common unit	$	$	$ 1.23
Distributions per unit	$	$	$ 2.06

Table of Contents

6. Investment in Unconsolidated Subsidiary

As described in the Acquisitions and Dispositions footnote, the Partnership contributed RIG to HPC for a 38 percent partner s interest in HPC. Subsequently, on September 2, 2009, the Partnership purchased an additional five percent partner s interest in HPC from EFS Haynesville for $63,000,000. The Partnership recognized $7,886,000 in income from unconsolidated subsidiary for its ownership interest and received $8,926,000 of distributions from HPC from inception (March 18, 2009) to December 31, 2009. The summarized financial information of HPC for the period from inception (March 18, 2009) to December 31, 2009 is disclosed below.

RIGS Haynesville Partnership Co.

Condensed Consolidated Balance Sheet

December 31, 2009

(in thousands)

ASSETS	
Total current assets	$ 39,239
Restricted cash, non-current	33,595
Property, plant and equipment, net	861,570
Total other assets	149,755
TOTAL ASSETS	$ 1,084,159
LIABILITIES & PARTNERS' CAPITAL	
Total current liabilities	$ 30,967
Partners' capital	1,053,192
TOTAL LIABILITIES & PARTNERS' CAPITAL	$ 1,084,159

RIGS Haynesville Partnership Co.

Condensed Consolidated Income Statement

From Inception (March 18, 2009) to December 31, 2009

(in thousands)

Total revenues	$ 43,483
Total operating costs and expenses	24,926
OPERATING INCOME	18,557
Interest expense	(158)
Other income and deductions, net	1,335
NET INCOME	$ 19,734

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 the Haynesville Expansion Project), less amounts reserved for normal operating expenses.

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.

Table of Contents

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

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

	As of December 31, 2009	
	2010	**2011**
NGLs	80%	33%
Condensate	84%	21%
Natural gas	85%	27%

At December 31, 2009, the 2010 and 2011 natural gas and 2010 condensate swaps are accounted for as cash flow hedges; the 2011 condensate swaps are accounted for using mark-to-market accounting; and the 2010 and 2011 NGLs swaps are accounted for using a combination of cash flow hedge accounting and mark-to-market accounting.

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, 2009, the Partnership had $419,642,000 of outstanding borrowings exposed to variable interest rate risk. In February 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (3.0 percent as of December 31, 2009) through March 5, 2010. These interest rate swaps were designated as cash flow hedges.

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 International Swap Dealers Association (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 is $25,246,000, which would be reduced by $13,284,000 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. Changes in the fair value are recorded in other income and deductions, net within the consolidated statement of operations. The Partnership

Table of Contents

does not expect the embedded derivatives to affect its cash flows. During the year ended December 31, 2009, the loss recognized related to these embedded derivatives was $15,686,000 and is reflected in other income and deductions, net on the consolidated statement of operations.

Quantitative Disclosures. The Partnership expects to reclassify $1,271,000 of net hedging losses to revenue or interest expense from accumulated other comprehensive income in the next 12 months.

The Partnership s derivative assets and liabilities, including credit risk adjustment, for the years ending December 31, 2009 and 2008 are detailed below.

	Assets		Liabilities	
	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
		(in thousands)		
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$	$	$ 1,067	$ 4,680
Commodity contracts	9,525	59,882	11,200	
Long-term amounts				
Interest rate contracts				560
Commodity contracts	207	13,373	931	
Total cash flow hedging instruments	9,732	73,255	13,198	5,240
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	15,514	16,001	31	38,402
Long-term amounts				
Commodity contracts		23,425	3,378	
Embedded derivatives in Series A Preferred Units			44,594	
Total derivatives not designated as cash flow hedges	15,514	39,426	48,003	38,402
Credit Risk Assessment				
Current amounts	(52)	(1,890)	(42)	(391)
Total derivatives	$ 25,194	$ 110,791	$ 61,159	$ 43,251

Derivatives designated as cash flow hedges

	Year Ended December 31, 2009			Year Ended December 31, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
			(in thousands)			
Gain (loss) recorded in accumulated OCI (Effective)	$ (2,082)	$ (19,958)	$ (22,040)	$ (4,555)	$ 74,808	$ 70,253
Gain (loss) reclassified from accumulated OCI into income (Effective)*	(6,255)	54,260	48,005	676	(35,942)	(35,266)
Gain (loss) recognized in income (Ineffective)*		108	108		543	543

Table of Contents

Derivatives not designated as cash flow hedges

	Year Ended December 31, 2009			Year Ended December 31, 2008		
	Embedded Derivatives	Commodity	Total	Embedded Derivatives	Commodity	Total
			(in thousands)			
Loss from dedesignation amortized from accumulated OCI into income*	$	$ (611)	$ (611)	$	$ (246)	$ (246)
(Loss) gain recognized in income*	(15,686)	(13,669)	(29,355)		15,911	15,911

Credit risk assessment for commodity and interest rate swaps

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Gain (loss) recognized in income*	$ 1,489	$ (1,499)	$

* Gain and loss related to commodity swaps, interest swaps and embedded derivatives were included in revenue, interest expense, and other income and deductions, net, respectively, in the Partnership s consolidated statements of operations.

8. Long-term Debt

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

	December 31, 2009	December 31, 2008
	(in thousands)	
Senior notes	$ 594,657	$ 357,500
Revolving loans	419,642	768,729
Total	1,014,299	1,126,229
Less: current portion		
Long-term debt	$ 1,014,299	$ 1,126,229
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded Lehman commitments	(10,675)	(8,646)
Revolving loans	(419,642)	(768,729)
Letters of credit	(16,257)	(16,257)
Total available	$ 453,426	$ 106,368

Long-term debt maturities as of December 31, 2009 for each of the next five years are as follows.

Year Ended December 31,	Amount (in thousands)
2010	$

2011	419,642
2012	
2013	357,500
2014	
Thereafter	250,000*
Total	$ 1,027,142

* As of December 31, 2009, the carrying value of the senior notes due 2016 was $237,157,000 which included an unamortized discount of $12,843,000.

Table of Contents

In the year ended December 31, 2009, the Partnership borrowed $191,693,000 under its credit facility; these borrowings were primarily to fund capital expenditures. During the same period, the Partnership repaid $540,780,000 with proceeds from an equity offering and issuance of senior notes due 2016. In the years ended December 31, 2008 and 2007, the Partnership borrowed $844,729,000 and $283,230,000, respectively; these funds were used primarily to finance capital expenditures. During the same periods, the Partnership repaid $200,000,000 and $421,430,000, respectively, of these borrowings with proceeds from equity offerings.

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 9.375 percent with interest payable semi-annually in arrears on June 1 and December 1. The Partnership paid a $13,760,000 discount upon issuance. The net proceeds were used to partially repay revolving loans under the Partnership s 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 until 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, 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 its debt agreements, including its 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.

The senior notes are jointly and severally guaranteed by all of the Partnership s current consolidated subsidiaries, other than Finance Corp., 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 unsubordinated 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 credit facility, to the extent of the value of the assets securing such obligations.

Senior Notes due 2013. In 2006, the Partnership and Finance Corp. issued $550,000,000 senior notes that mature on December 15, 2013 in a private placement. The senior notes bear interest at 8.375 percent and interest is payable semi-annually in arrears on each June 15 and December 15. In August 2007, the Partnership exercised its option to redeem 35 percent or $192,500,000 of these senior notes at a price of 108.375 percent of the principal amount plus accrued interest. Accordingly, a redemption premium of $16,122,000 and a loss on debt refinancing and unamortized loan origination costs of $4,575,000 were charged to loss on debt refinancing in the year ended December 31, 2007. Under the senior notes terms, no further redemptions are permitted until December 15, 2010.

The Partnership may redeem the outstanding senior notes, in whole or in part, at any time on or after December 15, 2010, at a redemption price equal to 100 percent of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest and liquidated damages, if any, to the redemption date.

Upon a change of control, 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 its debt agreements, including its 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.

The senior notes are jointly and severally guaranteed by all of the Partnership s current consolidated subsidiaries, other than Finance Corp., 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 unsubordinated 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 credit facility, to the extent of the value of the assets securing such obligations.

Finance Corp. has no operations and will not have revenue 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 certain wholly owned subsidiaries, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

GECC Credit Facility. On February 26, 2009, the Partnership entered into a $45,000,000 unsecured revolving credit agreement with GECC. The proceeds of the GECC Credit Facility were available for

expenditures made in connection with the Haynesville Expansion Project prior to the effectiveness of the March 17, 2009 amendment discussed below. The commitments under the GECC Credit Facility terminated on March 17, 2009. The Partnership paid a commitment fee of $2,718,000 to GECC related to this GECC Credit Facility, which was recorded as a decrease to gain on asset sales, net.

Fourth Amended and Restated Credit Agreement. In February 2008, RGS Fourth Amended and Restated Credit Agreement was expanded to $900,000,000 and the availability for letters of credit was increased to $100,000,000. The Partnership 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 credit facility have been met. The maturity date of the Credit Facility is August 15, 2011.

Effective March 17, 2009, RGS amended the credit facility to authorize the contribution of RIG to HPC and allow for a future investment of up to $135,000,000 in HPC. The amendment imposed additional financial restrictions that limit the ratio of senior secured indebtedness to EBITDA. 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 1.50 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 0.500 percent. On July 24, 2009, RGS further amended its credit facility to allow for a $25,000,000 working capital facility for RIG. These amendments did not materially change other terms of the RGS revolving credit facility.

On September 15, 2008, Lehman filed a petition in the United States Bankruptcy Court seeking relief under Chapter 11 of the United States Bankruptcy Code. As a result, a subsidiary of Lehman that is a committed lender under the Partnership s credit facility has declined requests to honor its commitment to lend. The total amount committed by Lehman was $20,000,000 and as of December 31, 2009, the Partnership had borrowed all but $10,675,000 of that amount. Since Lehman has declined requests to honor its remaining commitment, the Partnership s total size of the credit facility s capacity has been reduced from $900,000,000 to $889,325,000. Further, if the Partnership makes repayments of loans against the credit facility which were, in part, funded by Lehman, the amounts funded by Lehman may not be reborrowed.

The outstanding balance of revolving loans under the credit facility bears interest at LIBOR plus a margin or Alternative Base Rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 6.69 percent, 6.27 percent, and 8.78 percent for the years ended December 31, 2009, 2008, and 2007, respectively. The senior notes pay fixed interest rates and the weighted average rate is 8.787 percent.

RGS must pay (i) a commitment fee equal to 0.50 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 3.0 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 credit facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to adjusted EBITDA (as defined in the credit agreement) ratio less than 5.25, and adjusted EBITDA to interest expense ratio greater than 2.75 times. At December 31, 2009 and 2008, RGS and its subsidiaries were in compliance with these covenants.

The 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 extent of the Partnership s determination of available cash (so long as no default or event of default has occurred or is continuing). The

Table of Contents

credit facility also contains various covenants that limit (subject to certain exceptions and negotiated baskets), 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 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 credit facility or reasonable extensions thereof.

9. Other Assets

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

	Permits and Licenses	Contracts	Trade Names (in thousands)	Customer Relations	Total
Balance at January 1, 2008	$ 9,368	$ 68,436	$	$	$ 77,804
Additions		64,770	35,100	41,710	141,580
Amortization	(786)	(6,407)	(2,252)	(4,293)	(13,738)
Balance at December 31, 2008	8,582	126,799	32,848	37,417	205,646
Disposals	(2,921)				(2,921)
Other		7,000			7,000
Amortization	(569)	(7,467)	(2,340)	(2,055)	(12,431)
Balance at December 31, 2009	$ 5,092	$ 126,332	$ 30,508	$ 35,362	$ 197,294

The average remaining amortization periods for permits and licenses, contracts, trade names, and customer relations are 10, 16, 13 and 18 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	**Total (in thousands)**
2010	$ 12,553
2011	11,244
2012	11,002
2013	11,002
2014	11,002

Table of Contents

Goodwill. Goodwill activity consists of the following.

	Gathering and Processing	Transportation	Contract Compression	Total
		(in thousands)		
Balance at January 1, 2008	$ 59,831	$ 34,244	$	$ 94,075
Additions	3,401		164,882	168,283
Balance at December 31, 2008	63,232	34,244	164,882	262,358
Disposals		(34,244)		(34,244)
Balance at December 31, 2009	$ 63,232	$	$ 164,882	$ 228,114

On March 17, 2009, the Partnership contributed all assets of RIG, which owns the Regency Intrastate Gas System, to HPC, in exchange for an interest in HPC. As a result, goodwill associated with the transportation segment was removed from the balance sheet.

10. Fair Value Measures

On January 1, 2008, the Partnership adopted the fair value measurement provisions for financial assets and liabilities and on January 1, 2009, the Partnership applied the fair value measurement provisions to non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. These 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.

Derivatives. 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.

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

	December 31, 2009		December 31, 2008	
	Assets	Liabilities	Assets	Liabilities
		(in thousands)		
Level 1	$	$	$	$

Level 2	25,194	16,565	110,791	43,251
Level 3		44,594		
Total	$ 25,194	$ 61,159	$ 110,791	$ 43,251

Table of Contents

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the year ended December 31, 2009. There were no Level 3 derivatives for the years ended December 31, 2008 or 2007.

	Derivatives related to Series A Preferred Units For the Year Ended December 31, 2009 (in thousands)	
Beginning Balance	$	
Issuance		28,908
Net unrealized losses included in other income and deductions, net		15,686
Ending Balance	$	44,594

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 2013 based on third party market value quotations as of December 31, 2009 and 2008 was $364,650,000 and $244,888,000, respectively. The estimated fair value of the senior notes due 2016 based on third party market value quotations as of December 31, 2009 was $265,625,000.

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, 2009.

For the year ending December 31,	Operating	Capital
	(in thousands)	
2010	$ 3,838	$ 589
2011	3,801	422
2012	3,426	436
2013	2,714	448
2014	2,351	462
Thereafter	9,975	7,101
Total minimum lease payments	$ 26,105	$ 9,458
Less: Amount representing estimated executory costs (such as maintenance and insurance), including profit thereon, included in minimum lease payments		1,890
Net minimum lease payments		7,568
Less: Amount representing interest		4,365
Present value of net minimum lease payments		$ 3,203

Table of Contents

The following table sets forth the Partnership s assets and obligations under the capital lease which are included in other current and long-term liabilities on the consolidated balance sheet.

	December 31, 2009 (in thousands)
Gross amount included in gathering and transmission systems	$ 3,000
Gross amount included in other property, plant and equipment	560
Less accumulated depreciation	(755)
	$ 2,805
Current obligation under capital lease	529
Non-current obligation under capital lease	2,674
	$ 3,203

Total rent expense for operating leases, including those leases with terms of less than one year, was $5,465,000, $2,576,000, and $1,597,000, for the years ended December 31, 2009, 2008, and 2007, respectively.

12. Commitments and Contingencies

Legal. The Partnership is involved in various claims and lawsuits 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.

Escrow Payable. At December 31, 2009, $1,511,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement (El Paso PSA) related to assets in north Louisiana and the mid-continent area and a subsequent 2008 settlement agreement between the Partnership and El Paso. In the El Paso PSA, El Paso indemnified Regency Gas Services LLC, now known as Regency Gas Services LP, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities. This escrow amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion.

Environmental. A Phase I environmental study was performed on certain assets located in west Texas in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made against the Partnership or under the policy.

TCEQ Notice of Enforcement. In February 2008, the TCEQ issued a Notice of Enforcement (NOE) concerning one of the Partnership s processing plants located in McMullen County, Texas. The NOE alleged that, between March 9, 2006, and May 8, 2007, this plant experienced 15 emission events of various durations from four hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. In January 2010, the TCEQ notified the Partnership in writing that it had concluded that there had been no violation and that the TCEQ would take no further action.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC (Keyes) filed suit against Regency Gas Services LP, 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. Discovery ended in October 2009. A hearing on cross-motions for summary judgment took place in December 2009. A decision is expected in the first quarter of 2010. If the Partnership does not win its motion, a jury trial is scheduled for April 2010.

Kansas State Severance Tax. In August 2008, a customer began remitting severance tax to the state of Kansas based on the value of condensate purchased from one of the Partnership s Mid-Continent gathering fields and deducting the tax from its payments to the Partnership. The Kansas Department of Revenue advised the customer that it was appropriate to remit such taxes and withhold the taxes from its payments to the Partnership, absent an order or legal opinion from the Kansas Department of Revenue stating otherwise. The Partnership has requested a determination from the Kansas Department of Revenue regarding the matter since severance taxes were already paid on the gas from which the condensate is collected and no additional tax is due. The Kansas Department of Revenue has initiated an audit of the Partnership s condensate sales in Kansas. If the Kansas Department of Revenue determines that the condensate sales are taxable, then the Partnership may be subject to additional taxes, interest and possible penalties for past and future condensate sales.

Caddo Gas Gathering LLC v. Regency Intrastate Gas LLC. Regency Intrastate Gas LLC was a defendant in a lawsuit filed by Caddo Gas Gathering LLC (Caddo Gas). In February 2010, the dispute was resolved and the lawsuit dismissed with prejudice without material expense.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. Regency Field Services LLC (RFS) currently owns the Dubach and Calhoun gas processing plants in north Louisiana (the Plants). The Plants each have a groundwater contamination as result of historical operations. At the time that RFS acquired the Plants from 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.

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 will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010.

Distributions on the Series A Preferred Units will be 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. For the year ended December 31, 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 ending 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 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 commencing on March 2, 2010, 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.

Table of Contents

As of December 31, 2009, accrued distributions of $3,891,000 have been 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.

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)
Beginning balance as of January 1, 2009		$
Original issuance, net of discount of $3,200	4,371,586	76,624
Amount reclassed to long-term derivative liabilities		(28,908)
Accrued distributions		3,891
Accretion to redemption value		104
Ending balance as of December 31, 2009	4,371,586	$ 51,711

14. Related Party Transactions

In September 2008, HM Capital Partners 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 Partners is no longer a related party of the Partnership. During the years ended December 31, 2008 and 2007, HM Capital Partners and affiliates received cash disbursements, in conjunction with distributions by the Partnership for limited and general partner interests, of $10,308,000 and $24,392,000, respectively.

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 $33,834,000, $26,899,000, and $27,628,000, were recorded in the Partnership s financial statements during the years ended December 31, 2009, 2008, and 2007, respectively, as operating expenses or general and administrative expenses, as appropriate.

Concurrent with the GE EFS acquisition, eight members of the Partnership s senior management, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units for a total consideration of $24.00 per unit. Additionally, GE EFS entered into a subscription agreement with four officers and certain other management of the Partnership whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

GE EFS and certain members of the Partnership s management made capital contributions aggregating to $6,344,000, $11,746,000 and $7,735,000 to maintain the General Partner s two percent interest in the Partnership for the years ended December 31, 2009, 2008, and 2007, respectively.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS received cash distributions of $51,226,000, $35,054,000, and $14,592,000 during the years ended December 31, 2009, 2008 and 2007, respectively.

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.

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.

Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. Under this agreement the Partnership received $500,000 monthly as a partial reimbursement of its general and administrative costs. The Partnership also incurs expenditures on behalf of HPC and these amounts are billed to HPC on a monthly basis. For the period from March 18, 2009 to December 31, 2009, the related party general and administrative expenses reimbursed to the Partnership were $4,726,000. On December 18, 2009, the reimbursement amount was amended to $1,400,000 per month effective on the first calendar day in the month subsequent to mechanical completion of the expansion of the Regency Intrastate Gas System (February 1, 2010), subject to an annual escalation beginning March 1, 2011. The amount is recorded as fee revenue in the Partnership s corporate and other segment. Additionally, the Partnership s contract compression segment provides contract compression services to HPC. On the other hand, HPC provides transportation service to the Partnership.

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. Subsequently, the Partnership sold an additional $7,984,000 of compression equipment to HPC.

The Partnership s related party receivables and related party payables as of December 31, 2009 relate to HPC. The Partnership s related party receivables and related party payables as of December 31, 2008 related to CDM MAX.

As disclosed in Note 1 and in Note 5, the Partnership s acquisition of FrontStreet and contribution of RIGS to HPC are related party transactions.

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.

		Year Ended (in thousands)		
	Reportable Segment	**December 31, 2009**	**December 31, 2008**	**December 31, 2007**
Customer				
Customer A	Gathering and Processing	$ 123,524	*	*
Supplier				
Supplier A	Transportation	$ 14,053	$ 75,464	$ 17,930
Supplier A	Gathering and Processing	143,435	243,075	139,116

* 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.

Table of Contents

16. Segment Information

In 2009, the Partnership s management realigned the composition of its segments. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new alignment.

The Partnership has four reportable segments: (a) gathering and processing, (b) transportation, (c) contract compression and (d) corporate and others. Gathering and processing involves collecting raw natural gas from producer wells and transporting it to treating plants where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. Revenue and the associated cost of sales from the gathering and processing segment directly expose the Partnership to commodity price risk, which is managed through derivative contracts and other measures. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment. The Partnership, through its producer services function, primarily purchases natural gas from producers at gathering systems and plants connected to its pipeline systems and sells this gas at downstream outlets.

Following the initial contribution of RIG to HPC in March 2009, as well as the subsequent acquisition of an additional five percent interest in HPC, the transportation segment consists exclusively of the Partnership s 43 percent interest in HPC, for which equity method accounting applies. Prior periods have been restated to reflect the Partnership s then wholly-owned subsidiary of Regency Intrastate Gas LLC as the exclusive reporting unit within this segment. The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with other pipelines, storage facilities or end-use markets. RIG performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenue is primarily fee based and involves minimal direct exposure to commodity price fluctuations. The north Louisiana intrastate pipeline operated by this segment serves the Partnership s gathering and processing facilities in the same area and those transactions create a portion of the intersegment revenue shown in the table below.

The contract compression segment provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. The Partnership s integrated solutions include a comprehensive assessment of a customer s natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. The Partnership is responsible for the installation and ongoing operation, service, and repair of its compression units, which are modified as necessary to adapt to customers changing operating conditions. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of the intersegment revenues shown in the table below.

The corporate and others segment comprises regulated entities and the Partnership s corporate offices. Revenue in this segment includes the collection of the partial reimbursement of general and administrative costs from HPC.

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 revenue, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenue 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 revenue in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

Table of Contents

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

	Gathering and Processing	Transportation	Contract Compression (in thousands)	Corporate and Others	Eliminations	Total
External Revenue[1]						
Year ended December 31, 2009	$ 920,650	$ 9,078	$ 148,846	$ 10,923	$	$ 1,089,497
Year ended December 31, 2008	1,685,946	42,400	132,549	2,909		1,863,804
Year ended December 31, 2007	1,151,739	36,587		1,912		1,190,238
Intersegment Revenue[1]						
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)	
Year ended December 31, 2007	26,165	12,391		281	(38,837)	
Cost of Sales[1] [2]						
Year ended December 31, 2009	681,383	2,297	12,422	(65)	3,526	699,563
Year ended December 31, 2008	1,463,851	(13,066)	11,619		(54,071)	1,408,333
Year ended December 31, 2007	1,018,721	(3,570)		(169)	(38,837)	976,145
Segment Margin[1]						
Year ended December 31, 2009	230,512	11,714	141,028	11,284	(4,604)	389,934
Year ended December 31, 2008	264,405	66,888	125,503	3,248	(4,573)	455,471
Year ended December 31, 2007	159,183	52,548		2,362		214,093
Operation and Maintenance						
Year ended December 31, 2009	88,520	2,112	45,744	426	(5,976)	130,826
Year ended December 31, 2008	82,689	3,540	49,799	74	(4,473)	131,629
Year ended December 31, 2007	53,496	4,407		97		58,000
Depreciation and Amortization						
Year ended December 31, 2009	67,583	2,448	36,548	3,314		109,893
Year ended December 31, 2008	58,900	14,099	28,448	1,119		102,566
Year ended December 31, 2007	40,309	13,457		1,308		55,074
Income from Unconsolidated Subsidiary						
Year ended December 31, 2009		7,886				7,886
Year ended December 31, 2008						
Year ended December 31, 2007						
Assets						
December 31, 2009	1,046,619	453,120	926,213	107,462		2,533,414
December 31, 2008	1,101,906	325,310	881,552	149,871		2,458,639
Investment in Unconsolidated Subsidiary						
December 31, 2009		453,120				453,120
December 31, 2008						
Goodwill						
December 31, 2009	63,232		164,882			228,114
December 31, 2008	63,232	34,244	164,882			262,358
Expenditures for Long-Lived Assets						
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
Year ended December 31, 2007	112,813	15,658		1,313		129,784

(1) The December 31, 2008 and 2007 amounts differ from previously reported amounts primarily due to the presentation of intersegment revenue, cost of sales and segment margin elimination amounts in the elimination column as opposed to including these amounts in each respective segment column.

(2) The Partnership identified an $80,000,000 typographical error related to the gathering and processing segment cost of sales for the year ended December 31, 2007. The amount should have been $1,008,517,000 as opposed to $1,088,517,000. However this error did not have an impact to the consolidated cost of sales nor the gathering and processing segment margin for the year ended December 31, 2007. The Partnership corrected this typographical error, together with the revision of the presentation of intersegment cost of sales discussed above in its December 31, 2009 segment information disclosure.

Table of Contents

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

	December 31, 2009	Year Ended December 31, 2008 (in thousands)	December 31, 2007
Net income (loss) attributable to Regency Energy Partners LP	$ 140,398	$ 101,016	$ (13,836)
Add (deduct):			
Operation and maintenance	130,826	131,629	58,000
General and administrative	57,863	51,323	39,713
(Gain) loss on assets sales	(133,284)	472	1,522
Management services termination fee		3,888	
Transaction expenses		1,620	420
Depreciation and amortization	109,893	102,566	55,074
Income from unconsolidated subsidiary	(7,886)		
Interest expense, net	77,996	63,243	52,016
Loss on debt refinancing			21,200
Other income and deductions, net	15,132	(332)	(1,252)
Income tax (benefit) expense	(1,095)	(266)	931
Net income attributable to noncontrolling interest	91	312	305
Total segment margin	$ 389,934	$ 455,471	$ 214,093

17. Equity-Based Compensation

Common Unit Option and Restricted (Non-Vested) Units. The Partnership s LTIP for the Partnership s employees, directors and consultants covers an aggregate of 2,865,584 common units. Awards under the LTIP have been made since completion of the Partnership s IPO. All outstanding, unvested LTIP awards at the time of the GE EFS Acquisition vested upon the change of control. As a result, the Partnership recorded a one-time charge of $11,928,000 during the year ended December 31, 2007 that was recorded in general and administrative expenses. LTIP awards made subsequent to the GE EFS Acquisition generally vest on the basis of one-fourth of the award each year. Options expire ten years after the grant date. LTIP compensation expense of $5,590,000, $4,318,000, and $15,534,000, is recorded in general and administrative in the statement of operations for the years ended December 31, 2009, 2008, and 2007, respectively.

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 following assumptions apply to the options granted during the year ended December 31, 2007.

	For the Year Ended December 31, 2007
Weighted average expected life (years)	4
Weighted average expected dividend per unit	$ 1.51
Weighted average grant date fair value of options	$ 2.31
Weighted average risk free rate	4.60%
Weighted average expected volatility	16.0%
Weighted average expected forfeiture rate	11.0%

Table of Contents

The common unit options activity for the years ended December 31, 2009, 2008, and 2007 is as follows.

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			

2007

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *(in thousands)
Outstanding at the beginning of period	909,600	$ 21.06		
Granted	21,500	27.18		
Exercised	(149,934)	21.78		$ 1,738
Forfeited or expired	(42,498)	21.85		
Outstanding at end of period	738,668	21.05	8.2	9,104
Exercisable at the end of the period	738,668	21.05		9,104

* 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.

Table of Contents

The restricted (non-vested) common unit activity for the years ended December 31, 2009, 2008, and 2007 is as follows.

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

2007

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	516,500	$ 21.06
Granted	615,500	30.44
Vested	(684,167)	22.91
Forfeited or expired	(50,333)	27.20
Outstanding at the end of period	397,500	31.62

The Partnership will make distributions to non-vested restricted common units at the same rate and on the same dates as the common units. Restricted common units are subject to contractual restrictions against transfer which lapse over time; non-vested restricted units are subject to forfeitures on termination of employment. The Partnership expects to recognize $9,517,000 of compensation expense related to the grants under LTIP primarily over the next 1.91 years.

Phantom Units. During 2009, the Partnership awarded 308,200 phantom units to senior management and certain key employees. These phantom units are in substance two grants composed of (1) service condition grants (also defined as time-based grants in the LTIP plan document) with graded vesting occurring on March 15 of each of the following three years; and (2) market condition grants (also defined as performance-based grants in the LTIP plan document) with cliff vesting based upon the Partnership s relative ranking in total unitholder return among 20 peer companies, which peer companies are disclosed in Item 11 of the Partnership s Annual Report on Form 10-K for the year ended December 31, 2009. At the end of the measurement period (March 15, 2012) for the market condition grants, the phantom units will convert to common units in a ratio ranging from 0 to 150 percent. Upon a change in control, the market condition based grants will convert to common units at 150 percent and the service condition grants will convert to common on a one-for-one basis. For both the service condition grants and the market condition grants, distributions will be accumulated from the grant date and paid upon vesting at the same rate as the common units.

In determining the grant date fair value, the grant date closing price of the Partnership s common units on NASDAQ was used for the service condition awards. For the market condition awards, a Monte Carlo simulation

Table of Contents

was performed which incorporated variables mainly including the unit price volatility and the grant-date closing price of the Partnership s common units on NASDAQ.

The Partnership expects to recognize $1,753,000 of compensation expense related to non-vested phantom units over a period of 2.4 years. During the year ended December 31, 2009, the Partnership recognized $418,000 of expense, which was reflected in general and administrative expense in the statement of operations.

The following table presents phantom unit activity for the year ended December 31, 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

18. Subsequent Events

On January 26, 2010, the Partnership declared a distribution of $0.445 per outstanding common unit including units equivalent to the General Partner s two percent interest in the Partnership, and an aggregate distribution of approximately $728,000, with respect to incentive distribution rights, that was paid on February 12, 2010 to unitholders of record at the close of business on February 5, 2010.

Table of Contents

19. Quarterly Financial Data (Unaudited)

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) Attributable to Regency Energy Partners LP	Basic Earnings per Common and Subordinated Unit	Diluted Earnings per Common and Subordinated Unit	Basic and Diluted Earnings per Class D Common Unit
	(in thousands except earnings per unit)					
2009						
March 31	$ 290,125	$ 162,373	$ 148,389[1]	$ 1.85	$ 1.78	$ 0.11
June 30	253,542	23,207	5,890	0.07	0.06	
September 30	250,582	21,831	(10,504)	(0.16)	(0.16)	
December 31	295,248	17,225	(3,377)	(0.07)	(0.07)	
2008						
March 31[2]	$ 405,235	$ 25,877	$ 10,348	$ 0.13	$ 0.13	$ 0.21
June 30	546,705	26,512	9,972	0.12	0.12	0.26
September 30 [2]	547,175	64,956	48,907	0.64	0.61	0.26
December 31	364,689	46,628	31,789	0.39	0.38	0.26

(1) In March 2009, the Partnership contributed RIG to HPC, recognized a gain of $133,451,000 on the transaction. See Note 5 for further information.

(2) The operating income amount and basic and diluted earnings per Class D Common Unit disclosed above differs immaterially from the amount disclosed in the Form 10-Q.