Regency Energy Partners LP
Form 10-K
March 02, 2009

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2008

OR

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

For the transition period from to

Commission file number: 000-51757

REGENCY ENERGY PARTNERS LP

(Exact name of registrant as specified in its charter)

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

(214) 750-1771

(Registrant s telephone number, including area code)

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units of Limited Partner Interests	**The Nasdaq Global Select Market**

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and small reporting company in Rule 12b-2 of the Exchange Act. x Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer (Do not check if a smaller reporting company) ¨ Smaller reporting company

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

As of June 30, 2008, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $1,209,264,971 based on the closing sale price as reported on the NASDAQ Global Select Market.

There were 81,197,103 common units outstanding as of February 18, 2009.

DOCUMENTS INCORPORATED BY REFERENCE

None

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REGENCY ENERGY PARTNERS LP

ANNUAL REPORT ON FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2008

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Introductory Statement

References in this report to the Partnership, we, our, us and similar terms, when used in an historical context, refer to Regency Energy Partne LP, and 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 Pipeline I, L.P., a Delaware limited partnership
Alinda Investor II	Alinda Gas Pipeline 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
BBE	BlackBrush Energy, Inc., a wholly owned subsidiary of HM Capital Partners
BBOG	BlackBrush Oil & Gas, LP, an affiliate of HM Capital Partners
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
EIA	Energy Information Administration
EITF	Emerging Issues Task Force
EnergyOne	FrontStreet EnergyOne LLC
El Paso	El Paso Field Services, LP
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Finance Corp	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
FrontStreet	FrontStreet Hugoton LLC
GAAP	Accounting principles generally accepted in the United States
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
GSTC	Gulf States Transmission Corporation
HLPSA	Hazardous Liquid Pipeline Safety Act
HM Capital Partners	HM Capital Partners LLC
HMTF Gas Partners	HMTF Gas Partners II, L.P.
ICA	Interstate Commerce Act
IPO	Initial public offering of securities
IRS	Internal Revenue Service
Lehman	Lehman Brothers Holdings, Inc.
LIBOR	London Interbank Offered Rate

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Name	Definition or Description
MLP	Master limited partnership
LTIP	Long-Term Incentive Plan
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
Nexus	Nexus Gas Holdings, LLC
NOE	Notice of enforcement
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968, as amended
NPDES	National Pollutant Discharge Elimination System
Nasdaq	Nasdaq Global Select Market
NYMEX	New York Mercantile Exchange
OSHA	Occupational Safety and Health Act
Partnership	Regency Energy Partners LP
PHMSA	Pipeline and Hazardous Materials Safety Administration
Pueblo	Pueblo Midstream Gas Corporation
Pueblo Holdings	Pueblo Holdings, Inc.
RCRA	Resource Conservation and Recovery Act
RGS	Regency Gas Services LLC
Regency HIG	Regency Haynesville Intrastate Gas LLC
SCADA	System Control and Data Acquisition
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standard
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

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 and Section 21E of the Securities Exchange Act of 1934 (the Exchange Act). Forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as anticipate, believe, intend, project, plan, expect, estimate, goal, forecast, may or similar expressions help identify forward-looking statements. Although we believe our forward-lookin statements are based on reasonable assumptions and current expectations and projections about future events, we can not 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:

- 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;

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- the amount of collateral required to be posted from time to time in our transactions;
- changes in commodity prices, interest rates, 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;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of production from such facilities; and
- the effect of accounting pronouncements issued periodically by accounting standard setting boards.

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

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

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

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Part I

Item 1. Business

OVERVIEW

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

- *Gathering and Processing:* We provide wellhead-to-market services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems;

- *Transportation:* We deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Gas (RIGS) pipeline system; and

- *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. We operate more than 778,000 horsepower of compression for third party producers in Texas, Louisiana, and Arkansas. In addition, our contract compression segment operates approximately 196,000 horsepower of compression for our gathering and processing and transportation segments.

RECENT DEVELOPMENTS

On February 26, 2009 the Partnership, GECC and the Alinda Investors entered into a definitive agreement to form a joint venture to finance and construct our previously announced Haynesville Expansion Project. The project will transport gas from the Haynesville Shale, one of the fastest growing natural gas plays in the United States. In connection with the joint venture, we will contribute all of our ownership interests in RIGS, valued at $400,000,000, in exchange for a 38 percent general partnership interest in the joint venture and a cash payment equal to the total Haynesville Expansion Project capital expenditures paid through the closing date, subject to certain adjustments. GECC and the Alinda Investors have agreed to contribute $126,500,000 and $526,500,000 in cash, respectively, in return for a 12 percent and a 50 percent general partnership interest in the joint venture, respectively.

We will serve as the operator of the joint venture, and will provide all employees and services for the operation and management of the joint venture s assets. We expect to close the joint venture transaction as promptly as practicable following the satisfaction of the closing conditions, but no later than April 30, 2009.

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, marketing 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, butane, isobutane and natural gasoline. The NGL components are then sold to end users.

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The following diagram depicts our role in the process of gathering, processing, compression, marketing and transporting natural gas.

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 domestic consumption of natural gas is expected to increase from 21.6 Tcf in 2006 to 23.8 Tcf in 2016, representing an average annual growth rate of 1.0 percent, with a slight decrease in consumption through the year 2030. During the year ended December 31, 2006, the United States consumed 21.6 Tcf, down from 22.4 in 2005. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

Short-Term Energy Outlook. A recent report issued by the EIA projects a 1.3 percent decline in natural gas consumption in 2009 due to current economic conditions. In 2010, the report projects a 0.6 percent increase in consumption, depending on the timing and pace of economic recovery. Drilling activities in 2009 are expected to decline as a result of the sluggish demand for natural gas and lower commodity prices. Despite the decrease in drilling activities, production in 2009 from the lower forty-eight states is expected to increase by 1.1 percent due to the increase in gas supply from increased drilling activities in 2008, followed by a decrease of 1.1 percent in 2010.

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 larger diameter pipelines for further transportation. We own and operate large gathering systems in five geographic regions of the United States.

Compression. Gathering systems are operated at design pressures that seek to 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 gas that no longer naturally flows into a higher pressure downstream pipeline to be brought to market. Since wells produce at progressively lower field pressures as they age, the raw natural gas must be compressed to deliver the remaining production against a higher pressure that exists in the connected gathering system. Field compression is typically used to lower the entry pressure, while maintaining or increasing the exit pressure of a gathering system to allow it to operate at a lower receipt pressure and provide 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, the gas and amine are separated, and the impurities are removed from the amine by heating. The treating plants are sized by the amine circulation capacity in terms of gallons per minute. We own and operate natural gas processing and/or treating plants in three geographic regions: east, south and west Texas.

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

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.

Marketing. Natural gas marketing involves the sale of the pipeline-quality natural gas either produced by processing plants or purchased from gathering systems or other pipelines. We perform a limited natural gas marketing function for our account and for the accounts of our customers.

Transportation. Natural gas transportation consists of moving pipeline-quality natural gas from gathering systems, processing plants and other pipelines and delivering it to wholesalers, utilities and other pipelines.

GATHERING AND PROCESSING OPERATIONS

General. We operate significant gathering and processing assets in five geographic regions of the United States: north Louisiana, the mid-continent, 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 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, we remove any impurities in the raw natural gas stream and extract the NGLs.

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.

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The following table sets forth information regarding our gathering systems and processing plants as of December 31, 2008.

Region	Pipeline Length (Miles)	Plants	Compression (Horsepower)	Through-put Volume Capacity (MMcf/d)
North Louisiana	680	5	43,931	910
East Texas	371	1	14,597	215
South Texas	623	2	30,081	555
West Texas	806	1	46,134	355
Mid-Continent	3,470	1	48,931	437
Total	5,950	10	183,674	2,472

The following map depicts the geographic areas of our operations.

North Louisiana Region. Our north Louisiana region includes:

- two cryogenic natural gas processing plants;
- a large integrated natural gas gathering and processing system located primarily in five parishes (Claiborne, Union, Lincoln, DeSoto and Ouachita) of north Louisiana;
- a gathering system in Shelby County, Texas and Desoto Parish, Louisiana; and
- a refrigeration plant located in Bossier Parish, and a conditioning plant in Webster Parish.

Through this gathering and processing system and its interconnections with our RIGS pipeline system in north Louisiana described in Transportation Operations, we offer producers wellhead-to-market services, including natural gas gathering, compression, processing, marketing and transportation.

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The north Louisiana gathering system consists of 600 miles of natural gas gathering pipelines ranging in size from two inches to 10 inches in diameter. The system gathers raw natural gas from producers and delivers most of it to processing plants. The remainder of the raw natural gas is lean natural gas, which does not require processing and is delivered directly to interstate pipelines and RIGS.

A gathering system in Desoto Parish and Shelby County, Texas was acquired by the Partnership through its purchase of Nexus on March 25, 2008. This gathering system consists of 80 miles of natural gas gathering pipeline ranging in diameter from four to fourteen inches and is located in the Joaquin, Logansport, Spider and Benson Fields, which have experienced significant drilling activity. The system gathers lean natural gas from producers for delivery directly to interstate and intrastate pipelines.

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 the Eustace processing plant that is equipped with a sulfur removal unit. Natural gas produced in this region contains high levels of hydrogen sulfide.

The natural gas supply for our east 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.

Our east Texas processing plant is a cryogenic natural gas processing plant that was constructed in its current location in 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 gas at the plant outlet and produces sulfur.

South Texas Region. Our south Texas assets gather, compress, 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 hydrogen sulfide and carbon dioxide content and some of this gas is processed by third parties. These systems are connected to processing and treating facilities that include an acid gas reinjection well.

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.

One of our treating plants consists of inlet 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. An additional 55 MMcf/d amine treating unit is currently inactive. This plant removes hydrogen sulfide from the natural gas stream, which in this region often contains a high concentration of hydrogen sulfide and carbon dioxide, recovers condensate, delivers pipeline quality gas at the plant outlet and reinjects acid gas.

A second treating plant in Atascosa County includes a 500 gpm amine treater, pipeline interconnect facilities, and approximately 13 miles of ten inch diameter pipeline. We operate this plant with a joint venture partner that operates a lean gas gathering system in the Edwards Lime natural gas trend.

West Texas Region. Our gathering system offers wellhead-to-market services 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 this 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.

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The Waha processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Waha gathering system. This plant was constructed in 1965, and, due to recent upgrades to state of the art cryogenic processing capabilities, it 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 in our Waha gathering system before moving the natural gas to the processing plant. The acid gas is reinjected.

Mid-Continent Region. Our mid-continent region includes natural gas gathering systems located primarily in Kansas and Oklahoma. Our mid-continent gathering assets are extensive systems that gather, compress and dehydrate low-pressure gas from approximately 1,500 wells. These systems are geographically concentrated, with each central facility located within 90 miles of the others. We operate our mid-continent gathering systems at low pressures to increase the total through-put volumes from the connected wells. Wellhead pressures are therefore adequate to access 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, including the Hugoton Basin in southwest Kansas and the Anadarko Basin in western Oklahoma. These mature basins have continued to provide generally long-lived, predictable reserves.

TRANSPORTATION OPERATIONS

Regency Intrastate Gas Pipeline System. We own and operate a 320-mile intrastate natural gas pipeline system, known as RIGS, in north Louisiana extending from Caddo parish to Franklin parish. This system, with pipeline ranging from 12 to 30 inches in diameter, includes total system capacity of 910 MMcf/d, 26,370 horsepower of compression. Natural gas generally flows from west to east on the pipeline from wellhead connections or connections with other gathering systems. RIGS transports natural gas produced from the Elm Grove field, the Vernon field, and the Sligo field, which are three of the five largest natural gas producing fields in Louisiana.

In connection with the joint venture arrangement that we recently entered into with GECC and the Alinda Investors, we will contribute all of our ownership interests in RIGS to the joint venture.

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.

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, and Arkansas.

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The following tables set forth certain information regarding contract compression s revenue generating horsepower as of December 31, 2008 and 2007.

		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

		December 31, 2007	
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	41,958	7%	252
500-999	61,609	11%	99
1,000+	464,660	82%	307
	568,227	100%	658

OUR CONTRACTS

The table below provides the margin by product and percentage for the years ended December 31, 2008 and 2007.

Margin by Product	2008	2007
Net Fee	64%	43%
NGL	18	37
Gas	10	10
Condensate	5	8
Helium and Sulfur	3	2
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. During the year ended December 31, 2008, purchases in our gathering and processing segment from one producer represented 17.3 percent of the cost of gas and liquids on our consolidated statement of operations.

Transportation Contracts.

Fee Transportation Contracts. We provide natural gas transportation services on RIGS pursuant to contracts with natural gas shippers. These contracts are all fee-based. Generally, our transportation services are of two types: firm transportation and interruptible transportation. When we agree to provide firm transportation service,

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we become 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 our part, 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 we agree to provide interruptible transportation service, we become obligated to transport natural gas nominated and actually delivered by the shipper only to the extent that we have available capacity. The shipper pays no reservation charge for this service but pays a commodity charge for quantities actually shipped. We provide our transportation services under the terms of our contracts and under an operating statement that we have filed and maintain with the FERC with respect to transportation authorized under Section 311 of the NGPA.

Merchant Transportation Contracts. We perform a limited merchant function on RIGS. We purchase natural gas from producers or gas marketers at receipt points on our system at a price adjusted to reflect our transportation fee and transport that gas to delivery points on our system where we sell the natural gas at market price. We regard the margin with respect to those purchases and sales as the economic equivalent of a fee for our transportation service. During the year ended December 31, 2008, purchases in our transportation segment from one producer represented 5.3 percent of the cost of gas and liquids on our consolidated statement of operations. In the aggregate, 22.6 percent of the cost of gas and liquids in our gathering & processing and transportation segments were purchased from this producer.

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 same index price on the date of settlement.

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 customer 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 PanEnergy Louisiana Intrastate, 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

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Mid-Continent: DCP Midstream Partners, L.P., ONEOK Energy Marketing and Trading, L.P., and Penn Virginia Corporation.
Transportation. Competition in natural gas transportation is characterized 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, we typically receive gas from gathering facilities and deliver gas to intrastate and interstate markets. We compete with interstate and intrastate pipelines that have access to the same gathering facilities or production areas. Our major competitors in the natural gas transportation business are DCP Midstream Partners, L.P., CenterPoint Energy Transmission, Gulf South Pipeline, L.P. and Texas Gas Transmission, LLC.

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, 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 risk, we have implemented a risk management program under which we seek to:

- match sales prices of commodities, including natural gas, NGLs, condensate, sulfur, and helium, 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 consequence 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 marketing 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

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compressors is supplied by our customers without cost to us. Our indirect exposure to short-term volatility in natural gas and crude oil commodity prices is mitigated because natural gas and crude oil production, rather than exploration, is the primary demand driver for our contract compression services, and because our focus on field-wide applications reduces our dependence on individual well economics.

REGULATION

Industry Regulation

Intrastate Natural Gas Pipeline Regulation. RIGS is 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. RIGS transports interstate natural gas in Louisiana for many of its shippers pursuant to Section 311 of the NGPA. To the extent that RIGS transports natural gas in interstate service, its rates, terms and conditions of service are subject to the jurisdiction of the FERC. 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 the FERC are generally analogous to the cost-based rates that the FERC deems just and reasonable for interstate pipelines under the NGA.

On September 23, 2008, the FERC issued a Letter Order approving the continuation of RIGS maximum rates for Section 311 transportation services as follows: Firm Service reservation fee of $4.5625 per MMBtu monthly ($0.15 MMBtu daily) and commodity fee of $0.05 per MMBtu; Interruptible Service transportation fee of $0.20 per MMBtu; and Fuel Retention up to two percent of receipts. The FERC Letter order was the result of a settlement, which also permits RIGS maximum fuel retention rate to increase to two percent when new compression is added to the RIGS system. As part of the settlement RIGS also agreed to re-justify or establish new rates for its Section 311 services by May 1, 2011. The triennial rate review requirement is a standard settlement provision in most intrastate pipeline proceedings for Section 311 service.

FERC has adopted new regulations requiring certain major non-interstate pipelines to post, on a daily basis, receipt and delivery point capacities and scheduled flow information. 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 rehearing before the FERC and 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. The FERC has also issued a Notice of inquiry seeking comments related to transactional reporting requirements of intrastate pipelines providing NGPA Section 311 transportation services. The Notice of Inquiry specifically seeks comments regarding competitive impacts of having different reporting requirements for interstate pipelines and intrastate pipelines performing Section 311 services and the market transparency benefits of requiring Section 311 intrastate pipelines to comply with the same reporting requirements of interstate pipelines. It is possible that FERC may propose new regulations as a result of the Notice of Inquiry and that such rules could add to RIGS regulatory burden and costs.

Interstate Natural Gas Pipeline Regulation. The 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. The FERC s authority extends to:

- rates and charges for natural gas transportation and related services;

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- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between the pipeline and its energy affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- accounting rules for ratemaking purposes;
- acquisition and disposition of facilities;
- initiation and discontinuation of 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 differently than any other natural gas companies with whom 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 the FERC has used to establish a pipeline s status as a gatherer not subject to FERC 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 the FERC, the courts or the U.S. Congress.

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

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 and legislation pertaining to these matters may be considered or adopted from time to time. 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 FERC regulates the tariff rates for interstate NGL transportation and imposes reporting and a number of other requirements. Our NGL transportation tariff is required to be just and reasonable and not unduly discriminatory or confer any undue preference. FERC has established an indexing system for transportation rates for oil, NGLs and other products that allows for an annual inflation-based increase in the cost of transporting these liquids to the shipper. The implementation of these regulations has not had a material adverse effect on our results of operations. 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. We also have a Texas common carrier pipeline that provides intrastate transportation of crude oil subject to a local tariff approved by and on file with the TRRC. This pipeline is subject to a number of TRRC regulatory requirements governing rates and terms and conditions of service.

Sales of Natural Gas and NGLs. Our ability to sell gas in interstate markets is subject to FERC authority and its 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 Commodity Futures Trading Commission, 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.

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.

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

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.

Under an omnibus agreement, Regency Acquisition LP, the entity that formerly owned the General Partner, agreed to indemnify the Partnership in an aggregate not to exceed $8,600,000, generally for three years after February 3, 2006, for certain environmental noncompliance and remediation liabilities associated with the assets transferred to the Partnership and occurring or existing before that date. On February 3, 2009, the omnibus agreement expired, with no claims having been filed.

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

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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

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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 could cause us to incur additional costs or to become subject to operating restrictions or bans in the affected areas.

Climate Change. In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the Earth s atmosphere, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider, legislation to restrict or regulate emissions of greenhouse gases. 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.

Also, as a result of the United States Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s

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holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court s decision in *Massachusetts*. In the notice, EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although 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, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could also have an adverse affect on our cost of doing business and 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.

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.

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TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning one of the Partnership s processing plants located in McMullen County, Texas (the Plant). The NOE alleges that, between March 9, 2006, and May 8, 2007, the 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. On April 3, 2008, TCEQ presented the Partnership with a written offer to settle the allegation in the NOE in exchange for payment of an administrative penalty of $480,000, and it later reduced its settlement demand to $360,000 in July 2008. The Partnership was unable to settle this matter on a satisfactory basis and the TCEQ has referred the matter to its litigation division for further administrative proceedings.

EMPLOYEES

As of December 31, 2008, our General Partner employs 784 employees, of whom 560 are field operating employees and 224 are 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, Room 1580, 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.regencygasservices.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, or should 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.

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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 on our units 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 level 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 and not solely on profitability, which will be affected by non-cash items. 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.

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 revolving 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 exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of

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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 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 February 20, 2009, the unfunded commitment from Lehman is $5,578,000, thereby effectively reducing the amount available to us under our credit facility to $894,422,000. Upon the repayment of all of our existing outstanding borrowings, the amount available to us under our credit facility will be effectively reduced to $880,000,000. 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, 2008 was 50.9 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.

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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 we expect this volatility to continue. Recently, oil and natural gas prices have been extremely volatile and have declined substantially. On February 17, 2009, the price of oil on the New York Mercantile Exchange fell to $34.97 per barrel for March 2009 delivery from a high of $147.27 per barrel in July 2008. Volatility in 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 recent months, the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if additional natural gas reserves were discovered in areas served by our assets, producers may choose not to develop those reserves. If we were not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, 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 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. Additionally, many of our customers equity values have substantially declined. The combination of a reduction of cash flow resulting from recent 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. For example, a number of our customers have announced reduced drilling capital expenditure budgets for 2009. 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,

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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.

The completion of the joint venture with GECC and the Alinda Investors is subject numerous closing conditions and we may therefore not be able to successfully complete the joint venture.

Consummation of the joint venture transaction with GECC and the Alinda Investors is conditioned on receipt of certain third-party consents and certain other customary closing conditions. If such conditions are not satisfied and the joint venture is not consummated, we would not be able to fund the Haynesville Expansion Project. Credit markets have deteriorated and we believe that alternative financing for the Haynesville Expansion Project is not available on terms that are satisfactory to us. The curtailment of our Haynesville Expansion Project could have a material adverse effect on our results and on our future operations.

If the joint venture is completed, we may be required to make additional capital contributions to the joint venture.

If the joint venture is completed, its management committee may request that we, as 38 percent owners, 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.

If the joint venture is completed, we will own a 38 percent equity interest and will not be able to exercise control over the joint venture.

If the joint venture is completed, we will own a 38 percent ownership interest in the joint venture and GECC will own 12 percent. The joint venture will be managed by a management committee consisting of four members. Each investor will be entitled to appoint one member to the management committee and each member will have a vote equal to the sharing ratio of the partner that appointed such member. Accordingly, we will not be able to exercise control over the joint venture. In addition, the joint venture 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.

Our contract compression segment depends on particular suppliers and is vulnerable to product 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 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.

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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 the 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, we have executed swap contracts settled against ethane, propane, normal butane, iso-butane, natural gas, natural gasoline and west Texas intermediate crude market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant. Also, we may seek to limit our exposure to changes in interest rates by using financial derivative instruments and other hedging mechanisms from time to time. 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.

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. For example, we have agreed to reimburse the joint venture for the first $20,000,000 of cost overruns relating to the Haynesville Expansion Project. In addition, if the Haynesville Expansion Project is not completed at the

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budgeted cost, we may be required to make an additional capital contribution, which we may not be able to fund out of our operating cash flows and we may not be able to obtain financing on terms that are satisfactory to us. In general, the construction of additions or modifications to our existing systems, and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control. Any project that we undertake may not be completed on schedule, at budgeted cost or at all. Construction may occur over an extended period, and we are not likely to receive a material increase in revenues related to such project until it is completed. Moreover, our revenues may not increase immediately upon the completion of construction because the anticipated growth in gas production that the project was intended to capture does not materialize, our estimates of the growth in production prove inaccurate or for other reasons. For example, producers in the area may decrease their activity levels in the area near our Haynesville Expansion Project due to the current deterioration in the credit markets or the recent 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.

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.

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.

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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 and petrochemical 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.

If third-party pipelines interconnected to our processing plants become unavailable to transport NGLs, our cash flow and results of operations could be adversely affected.

We depend upon third party pipelines that provide delivery options to and from our processing plants for the benefit of our customers. If any of these pipelines become unavailable to transport the NGLs produced at our related processing plants, we would be required to find alternative means to transport the NGLs from our processing plants, which could increase our costs, reduce the revenues we might obtain from the sale of NGLs, or reduce our ability to process natural gas at these plants.

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. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our customers equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity 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 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.

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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, 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;
- 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.

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We currently estimate that we will incur costs of $1,622,000 in 2009 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 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.

Our interstate gas transportation operations, including Section 311 service performed by our intrastate 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 interstate or Section 311 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. 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. In addition, FERC regulates the rates, terms and conditions of service with respect to Section 311 transportation service provided by RIGS. The FERC also has policies and rules regarding the shipment of gas on interstate pipelines. 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. In addition, FERC has authority to alter its rules, regulations and policies to comply with its statutory authority. We cannot give any assurance regarding the likely future regulations under which RIGS or GSTC will operate its interstate transportation business or the effect such regulation could have on our business, results of operations, or ability to make distributions.

As a limited partnership entity, we may be disadvantaged in calculating its cost-of-service for rate-making purposes.

Under current policy applied under the NGA, FERC permits interstate 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 public utility 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. In connection with its future Section 311 rate case, RIGS may be required to demonstrate the extent to which inclusion of an income tax allowance in Regency s cost-of-service is permitted under the current income tax allowance policy. FERC policy also currently allows the inclusion of master limited partnerships 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 proposed as a member of the pipeline s proxy group. 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.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering 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. FERC s policies and practices, including, for example, its policies on open access transportation, ratemaking, capacity release. Market promotion indirectly affects intrastate markets, to the extent that RIGS provides interstate natural gas transmission service because its rates and terms and conditions of services are regulated by FERC pursuant to the NGPA. In recent years, FERC has pursued pro-competitive regulatory policies. However, with the passage of the Energy Policy Act of 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. In addition, FERC recently issued a notice of inquiry seeking comments regarding disparate reporting requirements between intrastate pipelines providing Section 311 services and interstate pipelines. We cannot predict the outcome of FERC s notice of inquiry proceeding or how FERC will approach future matters such as pipeline rates and rules and policies that may affect 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 lines 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. States in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination.

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.

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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. In response to such studies, President Obama has expressed support for and Congress is considering legislation to reduce emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. Also, 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 could result in future regulation of greenhouse gas emissions from stationary sources, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future. 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 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.

If a change of control (as defined in the indenture) 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 the indenture governing the senior notes, a change of control could also have occurred under the senior secured credit facilities, 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 indenture for our debt, we may not have sufficient funds to pay the purchase price of all debt that we are required to purchase or repay.

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

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

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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 these entities on our behalf;
- 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 affiliates of GECC may compete directly with us.

GE EFS and affiliates of GECC are not prohibited from owning assets or engaging in businesses that compete directly or independently with us. GE EFS and affiliates of GECC currently own various midstream

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assets and conduct midstream businesses that may potentially compete with us. In addition, GE EFS and affiliates of GECC 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 unit holders.

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 would 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 that our General Partner is entitled to make other decisions in good faith if it believes that the decision is in our best interests;

- 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, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

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

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders do not elect our General Partner or its Board of Directors and have no right to elect our General

Partner or its Board of Directors on an annual or other continuing basis. The Board of Directors of our General Partner is chosen by the members of our General Partner. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will 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.

The unitholders are currently unable to remove the General Partner without its consent because the General Partner and its affiliates own sufficient units to be able to prevent its removal. 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 18, 2009 our General Partner owns 30.4 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 the 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 to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the 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. 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.

Certain of our investors may sell units in the public market, which could reduce the market price of our outstanding common units.

Pursuant to agreements with investors in private placements or acquisitions, we have filed registration statements on Form S-3 registering sales by selling unitholders of an aggregate of 19,902,262 of our common units. The registered remaining unsold common units pursuant to these registration statements are 12,802,262. If

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investors holding these units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could temporarily reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

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 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, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of February 18, 2009 our General Partner owns 30.4 percent of the total of our common units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. In most states, a limited partner is only liable if he participates in the control of the business of the partnership. These statutes generally do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. You could, however, be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state s partnership statute; or

- your right to act with other unitholders to take other actions under our partnership agreement is found to constitute control of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the distribution, limited partners who received an impermissible distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make required contributions to the partnership other than contribution obligations that are unknown to the substituted limited partner at the time it became a limited partner and that could not be ascertained from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

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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.

Under Section 7704 of the Internal Revenue Code, a publicly traded partnership will be taxed as a corporation unless it satisfies the qualifying income exception that allows it to be treated as a partnership for U.S. federal income tax purposes. We believe that we meet the qualifying income exception and currently expect to meet such exception for the foreseeable future. If the IRS were to disagree and 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.

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.

We did not request a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. 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.

You 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, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from that income.

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Tax gain or loss on disposition of common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price is less than your 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 you sell your units, you may incur a tax liability in excess of the amount of cash you receive 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 you are a tax-exempt entity or a regulated investment company, you should consult your 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 you. 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 your 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, and, accordingly, if the IRS were to challenge this method 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 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.

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 and Arkansas. Each of these states, other than Texas, currently imposes a personal income tax as well as an income tax on corporations

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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 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.

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, except for those owned by one of our subsidiaries, by the Partnership and each such subsidiary. 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, 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 coverage 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. Submission of Matters to a Vote of Security Holders

None.

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Part II

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

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

Our common units were first offered and sold to the public on February 3, 2006. Our common units are listed on NASDAQ under the symbol RGNC. As of February 18, 2009, the number of holders of record of common units was 65, including Cede & Co., as nominee for Depository Trust Company, which held of record 48,833,125 common units. 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 NASDAQ, and the cash distributions declared per common unit.

	Price Ranges		Cash Distributions
Distribution Date	**High**	**Low**	**(per unit)**
2009			
First Quarter(2) (through February 18, 2009)	$ 12.47	$ 8.08	(3)
2008			
First Quarter(1)(2)	34.84	25.78	0.4000
Second Quarter(2)	28.73	23.93	0.4200
Third Quarter(2)	26.88	15.75	0.4450
Fourth Quarter(2)	19.00	4.92	0.4450
2007			
First Quarter	28.45	25.80	0.3800
Second Quarter	33.45	24.57	0.3800
Third Quarter	35.08	28.50	0.3900
Fourth Quarter	33.37	28.09	0.4000

(1) 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.

(2) 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.

(3) The cash distribution for the first quarter of 2009 will be determined in April 2009.

Cash Distribution Policy

We distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below. During the subordination period (as defined in our partnership agreement), the common units had the right to receive distributions of available cash from operating surplus in an amount equal to the MQD of $0.35 per quarter, plus any arrearages in the payment of the MQD on the common units from prior quarters, before any distributions of available cash could be made on the subordinated units. Our subordinated units converted to common units on February 17, 2009. 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

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provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

In addition to distributions on its 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.

	Total	Marginal Percentage Interest in Distributions	
	Quarterly Distribution Target Amount	Unitholders	General Partner
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	15
Third Target Distribution	above $0.4375 up to $0.5250	75	25
Thereafter	above $0.5250	50	50

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

On August 15, 2006, in connection with the TexStar acquisition, we issued 5,173,189 of Class B common units to HMTF Gas Partners as partial consideration for the TexStar acquisition. The total purchase price of the TexStar acquisition was $348,909,000. The Class B common units had the same terms and conditions as our common units, except that the Class B common units were not entitled to participate in distributions by the Partnership. The Class B common units were converted into common units without the payment of further consideration on a one-for-one basis on February 15, 2007. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

On September 21, 2006, we entered into a Class C Unit Purchase Agreement with certain purchasers, pursuant to which the purchasers purchased from us 2,857,143 Class C common units representing limited partner interests in the Partnership at a price of $21 per unit. The Class C common units had the same terms and conditions as the Partnership s common units, except that the Class C common units were not entitled to participate in distributions by the Partnership. The Class C common units were converted into common units without the payment of further consideration on a one-for-one basis on February 8, 2007. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

On April 2, 2007, in connection with the Pueblo Acquisition, we issued 751,597 common units to Bear Cub Investments, LLC and the members of that company as partial consideration for the Pueblo Acquisition. The total purchase price of the Pueblo acquisition was $54,634,000. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

On January 7, 2008, we issued 4,701,034 of Class E common units as partial consideration for the contribution of ASC s 95 percent ownership interest in FrontStreet. The total purchase price of the FrontStreet acquisition was $146,766,000. The Class E common units had the same terms and conditions as our common units, except that the Class E common units were not entitled to participate in distributions by the Partnership. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

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On January 15, 2008, we issued 7,276,506 of Class D common units to CDM OLP GP, LLC, the sole general partner of CDM, and CDMR Holdings, LLC, the sole limited partner of CDM, as partial consideration for the CDM Acquisition. The Class D common units have the same terms and conditions as our common units, except that the Class D common units are not entitled to participate in distributions by the Partnership until converted to common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units converted into common units on a one-for-one basis on February 9, 2009. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

There have been no other sales of unregistered equity securities during the last three years.

Item 6. Selected Financial Data

The historical financial information presented below for the Partnership and our predecessors, Regency LLC Predecessor and Regency Gas Services LP (formerly Regency Gas Services LLC), was derived from our audited consolidated financial statements as of December 31, 2008, 2007, 2006, and 2005, the one-month period ended December 31, 2004, and the eleven-month period ended November 30, 2004. 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.

We refer to Regency Gas Services LLC as Regency LLC Predecessor for periods prior to its acquisition by the HM Capital Investors.

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	Regency Energy Partners LP					Regency LLC Predecessor Period from Acquisition (December 1, 2004) to December 31, 2004
	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Acquisition (December 1, 2004 to December 31, 2004)	
	(in thousands except per unit data)					
Statement of Operations Data:						
Total revenue	$ 1,863,804	$ 1,190,238	$ 896,865	$ 709,401	$ 47,857	$ 432,321
Total operating expense	1,699,831	1,130,874	857,005	695,366	45,112	404,251
Operating income	163,973	59,364	39,860	14,035	2,745	28,070
Other income and deductions						
Interest expense, net	(63,243)	(52,016)	(37,182)	(17,880)	(1,335)	(5,097)
Loss on debt refinancing		(21,200)	(10,761)	(8,480)		(3,022)
Other income and deductions, net	332	1,252	839	733	64	186
Net income (loss) from continuing operations	101,062	(12,600)	(7,244)	(11,592)	1,474	20,137
Discontinued operations				732		(121)
Income tax expense (benefit)	(266)	931				
Minority interest	312	305				
Net income (loss)	$ 101,016	$ (13,836)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016
Less:						
Net income through January 31, 2006			1,564			
Net income (loss) for partners	$ 101,016	$ (13,836)	$ (8,808)			
General partner interest in net income (loss), including IDR	9,967	(393)	(176)			
Benefical conversion feature for Class C common units		1,385	3,587			
Benefical conversion feature for Class D common units	7,199					
Limited partner interest	$ 83,850	$ (14,828)	$ (12,219)			
Basic net income (loss) per common and subordinated unit	$ 1.27	$ (0.40)	$ (0.30)			
Diluted net income (loss) per common and subordinated unit	$ 1.24	(0.40)	(0.30)			
Cash distributions declared per common and subordinated unit	1.71	1.52	0.94			
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						
	0.99					

Income per Class D common unit due to beneficial conversion feature	
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

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	Regency Energy Partners LP					Regency LLC Predecessor
	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Acquisition (December 1, 2004 to December 31, 2004)	Period from Acquisition (December 1, 2004) to December 31, 2004
			(in thousands except per unit data)			
Balance Sheet Data (at period end):						
Property, plant and equipment, net	$ 1,703,554	$ 913,109	$ 734,034	$ 609,157	$ 328,784	
Total assets	2,458,639	1,278,410	1,013,085	806,740	492,170	
Long-term debt (long-term portion only)	1,126,229	481,500	664,700	428,250	248,000	
Net equity	1,086,252	563,293	212,657	230,962	181,936	
Cash Flow Data:						
Net cash flows provided by (used in):						
Operating activities	$ 181,298	$ 79,529	$ 44,156	$ 37,340	$ (4,311)	$ 32,401
Investing activities	(948,629)	(157,933)	(223,650)	(279,963)	(130,478)	(84,721)
Financing activities	734,959	99,443	184,947	242,949	132,515	56,380
Other Financial Data:						
Total segment margin(1)	$ 455,471	$ 214,093	$ 156,419	$ 76,536	$ 6,870	$ 69,559
EBITDA(1)	266,559	94,185	69,592	30,191	4,470	35,242
Maintenance capital expenditures	18,247	8,764	16,433	9,158	358	5,548
Segment Financial and Operating Data:						
Gathering and Processing Segment:						
Financial data:						
Segment margin	$ 256,380	$ 154,761	$ 111,372	$ 60,864	$ 6,262	$ 61,347
Operating expenses	82,689	53,496	35,008	22,362	1,655	16,230
Operating data:						
Natural gas throughput (MMbtu/d)	1,025,779	772,930	529,467	345,398	314,812	303,345
NGL gross production (Bbls/d)	22,390	21,808	18,587	14,883	16,321	14,487
Transportation Segment:						
Financial data:						
Segment margin	$ 78,161	$ 59,332	$ 45,047	$ 15,672	$ 608	$ 8,212
Operating expenses	3,614	4,504	4,488	1,929	164	1,556
Operating data:						
Throughput (MMbtu/d)	770,939	751,761	587,098	258,194	161,584	192,236
Contract Compression:						
Financial data:						
Segment margin	$ 125,503	N/A	N/A	N/A	N/A	N/A
Operating expenses	49,799	N/A	N/A	N/A	N/A	N/A

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

N/A Not applicable as we acquired these assets in January 2008.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: EBITDA and 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. EBITDA is used as a supplemental measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

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- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and General Partner;

- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and

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

EBITDA should not be considered an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

EBITDA does 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, to evaluate our performance.

We define total segment margin as total revenues, including service fees, less cost of gas and liquids. Total segment margin is included as a supplemental disclosure because it is a primary performance measure used by our management as it represents the results of product sales, service fee revenues and product purchases, a key component of our operations. We believe total segment margin is an important measure because it is 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 revenues in calculating total segment margin because we separately evaluate commodity volume and price changes in total segment margin. As an indicator of our operating performance, 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 may not be comparable to a similarly titled measure of another company because other entities may not calculate total segment margin in the same manner.

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	Regency Energy Partners LP					Regency LLC Predecessor
	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Acquisition Date (December 1, 2004) to December 31, 2004	Period from January 1, 2004 to November 30, 2004
				(in thousands)		
Reconciliation of EBITDA to net cash flows provided by (used in) operating activities and to net (loss) income						
Net cash flows provided by (used in) operating activities	$ 181,298	$ 79,529	$ 44,156	$ 37,340	$ (4,311)	$ 32,401
Add (deduct):						
Depreciation and amortization, including debt issuance cost amortization	(105,324)	(57,069)	(39,287)	(24,286)	(1,793)	(10,461)
Write-off of debt issuance costs		(5,078)	(10,761)	(8,480)		(3,022)
Equity income and minority interest in earnings	(312)	(262)	532	312	56	
Risk management portfolio value changes	14,700	(14,667)	2,262	(11,191)	322	
Loss (gain) on asset sales	(472)	(1,522)		1,254		
Unit based compensation expenses	(4,306)	(15,534)	(2,906)			
Gain on insurance settlement	3,282					
Trade accounts receivable and accrued revenues	(18,648)	28,789	5,506	43,012	(2,568)	19,832
Other current assets	6,615	1,394	(104)	2,644	2,456	1,169
Trade accounts payable, accrued cost of gas and liquids and accrued liabilities	40,772	(30,089)	1,359	(52,651)	(548)	(18,122)
Other current liabilities	(12,749)	149	(3,640)	(2,075)	1,163	(1,977)
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	(3,840)	(554)	(3,283)	3,261	6,697	196
Net (loss) income	$ 101,016	$ (13,836)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016
Add:						
Interest expense, net	63,243	52,016	37,182	17,880	1,335	5,097
Depreciation and amortization	102,566	55,074	39,654	23,171	1,661	10,129
Income tax expense	(266)	931				
EBITDA	$ 266,559	$ 94,185	$ 69,592	$ 30,191	$ 4,470	$ 35,242
Reconciliation of total segment margin to net (loss) income						
Net (loss) income	$ 101,016	$ (13,836)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016
Add (deduct):						
Operation and maintenance	131,629	58,000	39,496	24,291	1,819	17,786
General and administrative	51,323	39,713	22,826	15,039	645	6,571
Loss on asset sales	472	1,522				
Management services termination fee	3,888		12,542			
Transaction expenses	1,620	420	2,041			7,003
Depreciation and amortization	102,566	55,074	39,654	23,171	1,661	10,129
Interest expense, net	63,243	52,016	37,182	17,880	1,335	5,097
Loss on debt refinancing		21,200	10,761	8,480		3,022

Other income and deductions, net	(332)	(1,252)	(839)	(733)	(64)	(186)
Discontinued operations				(732)		121
Income tax expense	(266)	931				
Minority interest	312	305				
Total segment margin	$ 455,471	$ 214,093	$ 156,419	$ 76,536	$ 6,870	$ 69,559

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

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

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

OUR OPERATIONS. We divide our operations into three business segments:

- *Gathering and Processing:* We provide wellhead-to-market services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems;

- *Transportation:* We deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Pipeline system. The Partnership, GE EFS and Alinda entered into a definitive agreement to form a joint venture to finance and construct the Partnership s previously announced Haynesville Expansion Project. This project will more than double the capacity of RIGS in north Louisiana to bring natural gas from the Haynesville Shale, one of the most active new natural gas plays in the United States. The Partnership has secured commitments from shippers for 925 MMcf/d, which is more than 84 percent of the capacity of the Haynesville Expansion Project, and is in negotiations for the remaining capacity. The agreements are for firm transportation capacity under 10-year contract terms; and

- *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. We operate more than 762,000 horsepower of compression in Texas, Louisiana, and Arkansas. In addition, our contract compression segment operates approximately 196,000 horsepower of compression for our gathering and processing and transportation segments.

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 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 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. The following is a summary of our most common contractual arrangements:

- *Fee-Based Arrangements.* Under these arrangements, we generally are 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

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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, (3) the ability to bypass processing in unfavorable price environments or (4) conditioning floor fees that apply in adverse price environments.

Percent-of-proceeds and keep-whole arrangements involve commodity price risk to us because our 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 natural gasoline market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

Transportation segment. Results of operations from our Transportation segment are determined primarily by the volumes of natural gas transported on our Regency Intrastate Pipeline system and the level of fees charged to our customers or the margins received from purchases and sales of natural gas. We generate revenues and segment margins for our Transportation segment principally under fee-based transportation contracts or through the purchase of natural gas at one of the inlets to the pipeline and the sale of natural gas at an outlet. The margin we earn from our transportation activities is directly related to the volume of natural gas that flows through our system and is not directly dependent on commodity prices. If a sustained decline in commodity prices should result in a decline in volumes, our revenues from these arrangements would be reduced.

Generally, we provide to shippers two types of fee-based transportation services under our transportation contracts:

Firm Transportation. When we agree to provide firm transportation service, we become 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 our 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 us.

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Interruptible Transportation. When we agree to provide interruptible transportation service, we become obligated to transport natural gas nominated by the shipper only to the extent that we have available capacity. For this service the shipper pays no reservation charge but pays a commodity charge for quantities actually shipped.

We provide transportation services under the terms of our contracts and under an operating statement that we have filed and maintain with the FERC with respect to transportation authorized under section 311 of the NGPA.

In addition, we perform a limited merchant function on our Regency Intrastate Pipeline system. This merchant function is conducted by a separate subsidiary. We purchase natural gas from a producer or gas marketer at a receipt point on our system at a price adjusted to reflect our transportation fee and transport that gas to a delivery point on our 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 on the date of settlement.

We sell natural gas on intrastate and interstate pipelines to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies 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.

The Partnership, GECC and the Alinda Investors entered into a definitive agreement to form a joint venture to finance and construct our previously announced Haynesville Expansion Project. The project will transport gas from the Haynesville Shale, one of the fastest growing natural gas plays in the United States. In connection with the joint venture, we will contribute all of our ownership interests in RIGS, valued at $400,000,000, in exchange for a 38 percent general partnership interest in the joint venture and a cash payment equal to the total Haynesville Expansion Project capital expenditures paid through the closing date, subject to certain adjustments. GECC and the Alinda Investors have agreed to contribute $126,500,000 and $526,500,000 in cash, respectively, in return for a 12 percent and a 50 percent general partnership interest in the joint venture, respectively.

We will serve as the operator of the joint venture, and will provide all employees and services for the operation and management of the joint venture s assets. We expect to close the joint venture transaction as promptly as practicable following the satisfaction of the closing conditions, but no later than April 30, 2009. Please read Item 1 Business Overview.

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 778,000 horsepower of compression for third party producers in Texas, Louisiana, and Arkansas. In addition, our contract compression segment operates approximately 196,000 horsepower of compression for our gathering and processing and transportation segments.

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, and operating and maintenance expenses on a segment basis and EBITDA on a company-wide basis.

Volumes. We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and

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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.

To increase throughput volumes on our intrastate pipeline we must contract with shippers, including producers and marketers, for supplies of natural gas. We routinely monitor producer and marketing activities in the areas served by our transportation system in search of new supply opportunities.

Segment Margin. We calculate our gathering and processing segment margin as our revenue generated from our gathering and processing operations minus the cost of natural gas and NGLs purchased and other cost of sales, including third-party transportation and processing fees. Revenue includes revenue from the sale of natural gas and NGLs resulting from these activities and fixed fees associated with the gathering and processing of natural gas.

We calculate our transportation segment margin as revenue generated by fee income as well as, in those instances in which we purchase and sell gas for our account, gas sales revenue minus the cost of natural gas that we purchase and transport. Revenue primarily includes fees for the transportation of pipeline-quality natural gas and the margin generated by sales of natural gas transported for our account. Most of our segment margin is fee-based with little or no commodity price risk. We generally purchase pipeline-quality natural gas at a pipeline inlet price adjusted to reflect our transportation fee and we sell that gas at the pipeline outlet. We regard the difference between the purchase price and the sale price as the economic equivalent of our transportation fee.

We calculate our contract compression segment margin as revenue generated minus direct operating costs.

Total Segment Margin. Segment margin from gathering and processing, transportation, and contract compression segments comprise total segment margin. We use total segment margin as a measure of performance. See Item 6. Selected Financial Data Non-GAAP Financial Measures for a reconciliation of this non-GAAP financial measure, total segment margin, to its most directly comparable GAAP measures, net cash flows provided by (used in) operating activities and net income (loss).

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

EBITDA. We define EBITDA as net income plus interest expense, provision for income taxes and depreciation and amortization expense. EBITDA is used as a supplemental measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- 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.

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EBITDA should not be considered as an alternative to 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 master limited partnership. See Item 6 Selected Financial Data for a reconciliation of 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, Demand and Outlook. Natural gas remains a critical component of energy consumption in the United States. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

Even though overall drilling activity is forecasted to decline, drilling in the Haynesville Shale formation is expected to increase. According to Energy Intelligence (www.energyintel.com), the number of horizontal rigs at work in Haynesville has increased by 6 percent since October 2008. According to the report, several companies are shifting resources from the more developed Barnett Shale formation to the Haynesville Shale formation. The increased level of drilling activity is attributed to its resource potential and the producers obligation to drill to maintain the terms of their recently leased acreage.

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.

Effect of Interest Rates and Inflation. Interest rates on existing and future credit facilities and 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 in this regard to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

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

HISTORY OF THE PARTNERSHIP AND ITS PREDECESSOR

Formation of Regency Gas Services LLC. Regency Gas Services LLC was organized on April 2, 2003 by a private equity fund for the purpose of acquiring, managing, and operating natural gas gathering, processing, and transportation assets. Regency Gas Services LLC had no operating history prior to the acquisition of the assets from affiliates of El Paso Energy Corporation and Duke Energy Field Services, L.P. discussed below.

Acquisition of El Paso and Duke Energy Field Services Assets. In June 2003, Regency Gas Services LLC acquired certain natural gas gathering, processing, and transportation assets located in north Louisiana and the mid-continent region of the United States from subsidiaries of El Paso Corporation for $119,541,000. In March 2004, Regency Gas Services LLC acquired certain natural gas gathering and processing assets located in west Texas from Duke Energy Field Services, LP for $67,264,000, including transactional costs. Prior to our acquisitions, these assets were operated as components of the seller s much larger midstream operations. There were no material financial results for periods prior to June 2003.

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The HM Capital Investors Acquisition of Regency Gas Services LLC. On December 1, 2004, the HM Capital Investors acquired all of the outstanding equity interests in our predecessor, Regency Gas Services LLC, from its previous owners. The HM Capital Investors accounted for this acquisition as a purchase, and purchase accounting adjustments, including goodwill and other intangible assets, have been pushed down and are reflected in the financial statements of Regency Gas Services LLC for the period subsequent to December 1, 2004. This push down accounting increased depreciation, amortization and interest expenses for periods subsequent to December 1, 2004. We refer to this transaction as the HM Capital Transaction. For periods prior to the HM Capital Transaction, we designated such periods as Regency LLC Predecessor.

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.

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 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.

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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 (Merger Sub) consummated an agreement and plan of merger (the Merger Agreement) 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.

RESULTS OF OPERATIONS

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)		
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 expense (benefit)	(266)	931	(1,197)	129
Minority interest	312	305	7	2
Net income (loss)	$ 101,016	$ (13,836)	$ 114,852	830
System inlet volumes (MMBtu/d)(2)	1,522,431	1,225,918	296,513	24%

(1) For reconciliation of segment margin to its 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

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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)		
Gathering and Processing Segment				
Financial data:				
Segment margin(1)	$ 256,380	$ 154,761	$ 101,619	66%
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:				
Segment margin(1)	$ 78,161	$ 59,332	$ 18,829	32%
Operation and maintenance(2)	3,614	4,504	(890)	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
Operation and maintenance(2)	49,799		N/A	N/A

(1) For reconciliation of segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Item 6. Selected Financial Data. Combined segment margin for our segments differs from consolidated total 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.

N/A Not applicable as we acquired these assets in January 2008.

Net Income. Net income for the year ended December 31, 2008 increased $114,852,000 or 830 percent, compared with the year ended December 31, 2007. The increase in net income 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 described in SFAS No. 141, Business Combinations 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 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;

an increase in general and administrative expenses of $11,610,000 primarily due to our contract compression assets acquired in January 2008 and increased employee-related expenses, reduced by the

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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.

Segment Margin. Total segment margin for the year ended December 31, 2008 increased $241,378,000 compared with the year ended December 31, 2007. This increase was attributable to an increase of $101,619,000 in gathering and processing segment margin and an increase of $18,829,000 in transportation segment margin and the addition of $125,503,000 in contract compression segment margin, discussed below. Combined segment margin for our segments differs from consolidated total segment margin due to inter-segment eliminations of $4,573,000.

Gathering and processing segment margin increased to $256,380,000 for the year ended December 31, 2008 from $154,761,000 for the year ended December 31, 2007. The major components of this increase were as follows:

$29,657,000 from non-cash changes in the value of certain risk management contracts related to our hedging programs;

$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; and partially offset by

$(1,419,000) from other sources.

Transportation segment margin increased to $78,161,000 for the year ended December 31, 2008 from $59,332,000 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;

$4,705,000 in increased margins associated with our limited marketing function; 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.

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 assets acquired 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 the year ended December 31, 2008 compared to the same period in 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.

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.

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Year Ended December 31, 2007 vs. Year Ended December 31, 2006

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

	Year Ended December 31,			
	2007	2006	Change	Percent
		(in thousands)		
Total revenues	$ 1,190,238	$ 896,865	$ 293,373	33%
Cost of gas and liquids	976,145	740,446	235,699	32
Total segment margin[(1)]	214,093	156,419	57,674	37
Operation and maintenance	58,000	39,496	18,504	47
General and administrative[(2)]	39,713	22,826	16,887	74
Loss on asset sales, net	1,522		1,522	n/m
Management services termination fee		12,542	(12,542)	100
Transaction expenses	420	2,041	(1,621)	79
Depreciation and amortization	55,074	39,654	15,420	39
Operating income	59,364	39,860	19,504	49
Interest expense, net	(52,016)	(37,182)	(14,834)	40
Loss on debt refinancing	(21,200)	(10,761)	(10,439)	97
Other income and deductions, net	1,252	839	413	49
Loss before income taxes	(12,600)	(7,244)	(5,356)	74
Income tax expense	931		931	n/m
Minority interest	305		305	n/m
Net loss	$ (13,836)	$ (7,244)	$ (6,592)	91
System inlet volumes (MMBtu/d)[(3)]	1,225,918	1,010,642	215,276	21%

(1) For reconciliation of segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Item 6. Selected Financial Data.
(2) Includes a one-time charge of $11,928,000 related to our long-term incentive plan associated with the vesting of all outstanding common units options and restricted common units on June 18, 2007 with the change in control from HM Capital to GE EFS.
(3) System inlet volumes include total volumes taken into our gathering and processing and transportation systems.
n/m not meaningful

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

	Year Ended December 31,			
	2007	2006 (in thousands)	Change	Percent
Gathering and Processing Segment				
Financial data:				
Segment margin(1)	$ 154,761	$ 111,372	$ 43,389	39%
Operation and maintenance	53,496	35,008	18,488	53
Operating data:				
Throughput (MMBtu/d)	772,930	529,467	243,463	46
NGL gross production (Bbls/d)	21,808	18,587	3,221	17
Transportation Segment				
Financial data:				
Segment margin(1)	$ 59,332	$ 45,047	$ 14,285	32%
Operation and maintenance	4,504	4,488	16	0
Operating data:				
Throughput (MMBtu/d)	751,761	587,098	164,663	28

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

Net Loss. Net loss for the year ended December 31, 2007 increased $6,592,000 compared with the year ended December 31, 2006. An increase in total segment margin of $57,674,000, primarily due to organic growth in the gathering and processing segment; the absence in 2007 of management services termination fees of $12,542,000 from our initial public offering and TexStar Acquisition; and a decrease in transaction expenses of $1,621,000 associated with acquisitions of entities under common control were more than offset by:

- an increase in general and administrative expense of $16,887,000 primarily due to a one-time charge of $11,928,000 related to our long-term incentive plan associated with the vesting of all outstanding common unit options and restricted common units on June 18, 2007 with the change in control from HM Capital to GE EFS and higher employee related expenses;

- an increase in interest expense, net of $14,834,000 primarily due to increased levels of borrowings used primarily to finance our Pueblo Acquisition and growth capital projects;

- an increase in loss on debt refinancing of $10,439,000 primarily due to a $16,122,000 early termination penalty in 2007 associated with the redemption of 35 percent of our senior notes partially offset by a $5,683,000 decrease in the write-off of capitalized debt issuance costs related to paying off or refinancing credit facilities;

- $5,792,000 net income attributable to our FrontStreet assets;

- an increase in depreciation and amortization of $15,420,000 primarily due to higher levels of depreciation from projects completed since December 31, 2006 and our Pueblo Acquisition; and a net loss on the sale of certain non-core assets of $1,522,000 in the year ended December 31, 2007.

Segment Margin. Total segment margin for the year ended December 31, 2007 increased $57,674,000 compared with the year ended December 31, 2006. This increase was attributable to an increase of $43,389,000 in gathering and processing segment margin and an increase of $14,285,000 in transportation segment margin as discussed below.

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Gathering and processing segment margin increased to $154,761,000 for the year ended December 31, 2007 from $111,372,000 for the year ended December 31, 2006. The major components of this increase were as follows:

- $23,233,000 attributable to organic growth projects in the east and south Texas regions
- $22,184,000 attributable to our FrontStreet assets;
- $15,538,000 attributable to organic growth in the north Louisiana region; and offset by
- $17,449,000 of non-cash losses from certain risk management activities.

Transportation segment margin increased to $59,332,000 for the year ended December 31, 2007 from $45,047,000 for the year ended December 31, 2006. The major components of this increase were as follows:

- $11,512,000 attributable to increased throughput volumes;
- $1,752,000 of increased margins related to our merchant function;
- $631,000 attributable to increased margins per unit of throughput; and
- $390,000 of non-cash gains from certain risk management activities.

Operation and Maintenance. Operations and maintenance expense increased to $58,000,000 in the year ended December 31, 2007 from $39,496,000 for the corresponding period in 2006, a 47 percent increase. This increase is primarily the result of the following factors:

- $12,526,000 attributable to our FrontStreet assets;
- $3,217,000 of increased employee related expenses primarily in the gathering and processing segment resulting from additional employees related to organic growth and employee annual pay raises;
- $1,219,000 of increased consumable expenses primarily in the gathering and processing segment largely resulting from additional compression;
- $1,034,000 of increased contractor expense primarily in the gathering and processing segment associated with our Fashing processing plant;

- $811,000 of increased utility expense primarily in the gathering and processing segment resulting from one of our north Louisiana refrigeration plants placed in service in December 2006; and

- $637,000 of unplanned outage expense in the transportation segment in 2007 related to the Eastside compressor fire, which represents our estimated thirty day deductible.

Partially offsetting these increases in operation and maintenance expense were the following factors:

- $1,741,000 of insurance proceeds associated with our unplanned compressor outage in the transportation segment in 2007; and

- $549,000 of decreased rental expense primarily in the gathering and processing segment from fewer leased compressor units.

General and Administrative. General and administrative expense increased to $39,713,000 in the year ended December 31, 2007 from $22,826,000 for the same period in 2006, a 74 percent increase. The increase is primarily due to:

- a one-time charge of $11,928,000 related to our long-term incentive plan associated with the vesting of all outstanding common unit options and restricted common units on June 18, 2007 with the change in control from HM Capital to GE EFS;

- $3,607,000 of increased employee related expenses resulting from pay raises and the hiring of additional employees;

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- $777,000 of increased professional and consulting expense primarily for Sarbanes-Oxley compliance; and

- partially offsetting these increases was the absence in 2007 of management fees of $361,000 in 2006.

Other. In the year ended December 31, 2006, we recorded charges of $12,542,000 for the termination of long-term management services contracts in connection with our initial public offering and TexStar acquisition. In the years ended December 31, 2007 and 2006, we incurred transaction expenses of $420,000 related to our 2008 FrontStreet acquisition and $2,041,000 related to our TexStar acquisition. Since these acquisitions involve entities under common control, we accounted for these transactions in a manner similar to pooling of interests and expensed the transaction costs. In the year ended December 31, 2007, we sold certain non-core assets and recorded a related net charge of $1,522,000.

Depreciation and Amortization. Depreciation and amortization expense increased to $55,074,000 in the year ended December 31, 2007 from $39,654,000 for the year ended December 31, 2006, a 39 percent increase. The increase is due to higher depreciation expense of $13,914,000 primarily from projects completed since December 31, 2006, our Pueblo acquisition, and our FrontStreet assets. Also contributing to the increase was higher identifiable intangible asset amortization of $1,506,000 primarily related to contracts associated with the Pueblo acquisition and the TexStar acquisition in April 2007 and July 2006, respectively.

Interest Expense, Net. Interest expense, net increased $14,834,000, or 40 percent, in the year ended December 31, 2007 compared to the same period in 2006. Of this increase, $8,243,000 was attributable to increased levels of borrowings and $4,026,000, was attributable to higher interest rates partially offset by the 2006 reclassification of $2,607,000 from accumulated other comprehensive income associated with the gain upon the termination of an interest rate swap.

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. In the year ended December 31, 2006, we wrote-off $5,626,000 of debt issuance costs to amend and restate our credit facility and we wrote-off $5,135,000 of debt issuance costs associated with paying off TexStar s loan agreement as part of our TexStar acquisition.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

- cash generated from operations;

- borrowings under our credit facility;

- operating lease facilities;

- debt offerings; and

- issuance of additional partnership units.

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs, particularly as a result of our Haynesville Expansion Project. At December 31, 2008, the Partnership has purchase obligations totaling approximately $323,341,000, of which $104,852,000 is related to the purchase of major compression components unrelated to the Haynesville Expansion Project, that extend until the year ending December 31, 2010 and $218,489,000 of which is related to the Haynesville Expansion Project that extend until the year ending December 31, 2009. Some of these commitments have cancellation provisions.

The Partnership, GECC and the Alinda Investors entered into a definitive agreement to form a joint venture to finance and construct our previously announced Haynesville Expansion Project. The project will transport gas from the Haynesville Shale, one of the fastest growing natural gas plays in the United States. In connection with the joint venture, we will contribute all of our ownership interests in RIGS, valued at $400,000,000, in exchange for a 38 percent general partnership interest in the joint venture and a cash payment equal to the total Haynesville Expansion Project capital expenditures paid through the closing date, subject to certain adjustments. The GE Investor and the Alinda Investors have agreed to contribute $126,500,000 and $526,500,000 in cash, respectively, in return for a 12 percent and a 50 percent general partnership interest in the joint venture, respectively.

In the future, the management committee of the joint venture may request that we make additional capital contributions to support the joint venture s capital expenditures. If such capital contributions are required, we may not be able to obtain the financing necessary to satisfy our obligations. In addition, we have agreed to reimburse the joint venture for the first $20,000,000 of cost overruns relating to the Haynesville Expansion Project.

The Partnership has secured commitments from shippers for 925 MMcf/d, which is more than 84 percent of the capacity of the Haynesville Expansion Project, and is in negotiations for the remaining capacity. The agreements are for firm transportation capacity under 10-year contract terms.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding. The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. We expect that our ability to issue debt and equity at prices that are similar to offerings in recent years will be limited as long as capital markets remain constrained. Our planned internal growth projects continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them. As a result, we will continue to be opportunistic in our approach to funding the remaining expenditures from additional issuances of our equity and long-term debt.

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. For example, as a result of 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. The total amount available to us under our credit facility as of February 20, 2009 was $42,410,000, which has been reduced by the amount of Lehman s commitment of $5,578,000 that is no longer available to us. If we repay any of the amounts we have already borrowed from Lehman, we may not be able to reborrow such amounts. 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 are unable or unwilling to fund their respective portion of any funding request we make under our credit facility.

In addition, we have entered into a $75,000,000 operating lease facility with Caterpillar Financial Services Corporation and a $45,000,000 revolving credit facility with GECC as further described below.

We expect to reduce our growth capital expenditures in 2009 and 2010, from approximately $300,000,000 per year to approximately $120,000,000 in 2009 and $100,000,000 in 2010. As a result of our reduced capital expenditure plans, our need to access the debt and equity markets will be significantly reduced.

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 muted by substantial cost of capital increases during this period. As a result of these costs our cash flows may decrease, which could impair our liquidity position and require us to reduce our distributions to unitholders.

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Finally, if there is a significant lessening in demand for our services as a result of extended declines in the actual and longer term expected price of oil and gas, we may see a further reduction in our own capital expenditures and lesser requirements for working capital, both of which could generate operating cash flow and liquidity compared to the prior period and offset reduced cash generated from operations excluding working capital changes. However, such an environment might also increase the availability of acquisitions which could draw on such liquidity.

Working Capital Surplus (Deficit). Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. When we incur growth capital expenditures, we 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 risk management assets and liabilities due to fair market value changes in our derivative positions being reflected on our balance sheet. These represent our expectations for the settlement of risk management rights and obligations over the next 12 months, and so must be viewed differently from trade accounts receivable and accounts payable which settle over a much shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect risk management assets and liabilities to affect our ability to pay bills as they come due. Our contract compression segment records deferred revenues, a current liability. The deferred revenues represent billings in advance of services performed. As the revenues associated with the deferred revenues are earned, the liability is reduced.

Our working capital surplus at December 31, 2008 was $19,453,000 as compared to a working capital deficit of $18,365,000 at December 31, 2007, a $37,818,000 increase primarily due to the following factors:

- a $69,154,000 increase in working capital due to the value of risk management activities shifting from current liabilities to current assets resulting from a decrease in commodity prices we expect to pay (index prices) on our outstanding swaps versus the fixed commodity prices we expect to receive upon settlement;

- $7,170,000 increase in working capital resulting from an increase in net account receivable and payable due to the timing of cash receipts and payments;

- a $6,615,000 increase in working capital resulting from an increase in other current assets primarily due to an increase in insurance and other pre-paid expenses of $3,887,000, equipment inventory of $1,567,000, and NGL inventory of $1,041,000; and

Partially offsetting these increases in working capital were the following factors:

- a decrease in cash and cash equivalents of $32,372,000 due to the timing of cash receipts and payments associated with ongoing business operations; and

- an increase in other current liabilities of $12,749,000 primarily related to an increase in deferred revenues associated with business operations of our contract compression segment.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased $101,769,000, or 128 percent, for the year ended December 31, 2008 as compared to 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 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.

Net cash flows provided by operating activities increased $35,373,000, or 80 percent, for the year ended December 31, 2007 as compared to the year ended December 31, 2006. Cash generated from operations increased primarily due to increased total segment margin of $57,674,000, primarily due to organic growth in the gathering and processing segment and from operating activity of FrontStreet assets acquired on June 18, 2007.

For all periods, we used our cash flows from operating activities together with borrowings under our revolving credit facility for our working capital requirements, which include operation and maintenance

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expenses, maintenance capital expenditures and repayment of working capital borrowings. From time to time during each period, the timing of receipts and disbursements required us to borrow under our revolving credit facility. The maximum amounts of revolving line of credit borrowings outstanding during the years ended December 31, 2008 and 2007 were $809,000,000 and $178,930,000, respectively.

Cash Flows from Investing Activities. Net cash flows used in investing activities increased $790,696,000 or 501 percent, in the year ended December 31, 2008 compared to the year ended December 31, 2007. The increase is primarily due to organic growth in the gathering and processing segment and cash consideration paid for the contract compression, FrontStreet, and Nexus assets in the first calendar quarter of 2008.

Growth Capital Expenditures. In the year ended December 31, 2008, we incurred $354,727,000 of growth capital expenditures. Growth capital expenditures for the year ended December 31, 2008 primarily relate to the following projects:

- $176,740,000 for the fabrication of new compression packages and ancillary assets for our contract compression segment;
- $123,383,000 for various projects in the gathering and processing segment, primarily in Louisiana and Texas; and
- $54,604,000 in our transportation segment for the Haynesville Expansion Project.

Maintenance Capital Expenditures. In the year ended December 31, 2008, we incurred $18,247,000 of maintenance capital expenditures. Maintenance capital expenditures primarily consist of compressor and plant overhauls, as well as replacement or repair of equipment.

Net cash flows used in investing activities decreased $65,717,000, or 29 percent, in the year ended December 31, 2007 compared to the year ended December 31, 2006. The decrease is primarily due to our 2006 Como assets acquisition ($81,695,000), proceeds from the asset sales in 2007 of $11,706,000, a decrease in spending on growth and maintenance capital expenditures of $12,639,000, partially offset by our 2007 Pueblo acquisition ($34,855,000).

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased $635,516,000, or 639 percent, in the year ended December 31, 2008 compared to 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.

Net cash flows provided by financing activities decreased $85,504,000, or 46 percent, in the year ended December 31, 2007 compared to the year ended December 31, 2006 primarily due to the following:

- a decrease in borrowings under our credit facility of $599,650,000 due to restructuring our capitalization;

an increase in partner distributions of $42,789,000 due to increased distributions per unit and an increase in the number of partner units receiving distributions, no partner distributions paid in the quarter ended March 31, 2006 and a partial partner distribution paid in the quarter ended June 30, 2006 resulting from the timing of our initial public offering;

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an increase in proceeds from equity issuances of $40,846,000 due to the issuance in 2007 of 11,500,000 common units for $353,546,000, net of issuance costs, the proceeds of which were used to repay 35 percent or $192,500,000 of our senior notes, to repay our $50,000,000 term loan, and to pay down our revolving credit facility. In 2006 we issued 13,750,000 common units in our initial public offering and 2,857,143 Class C common units for $312,700,000, net of issuance costs; and

an increase in FrontStreet and contribution of $9,695,000 and $13,417,000 respectively.

Capital Resources

Description of Our Indebtedness. As of December 31, 2008, our aggregate outstanding indebtedness totaled $1,126,229,000 and consisted of $768,729,000 in borrowings under our revolving credit facility and $357,500,000 of outstanding senior notes as compared to our aggregate outstanding indebtedness as of December 31, 2007, which totaled $481,500,000 and consisted of $124,000,000 in borrowings under our revolving credit facility and $357,500,000 of outstanding senior notes.

Credit Ratings. Our credit ratings as of December 31, 2008 are provided below.

	Moody s	**Standard & Poor s**
Regency Energy Partners LP		
Corporate rating/total debt	Ba3	BB-
Senior notes	B1	B
Outlook	Negative Outlook	Negative Outlook

Fourth Amended and Restated Credit Agreement. We have a $ 900,000,000 revolving credit facility. The availability for letters of credit is $100,000,000. We have the option to request an additional $250,000,000 in revolving or term loan commitments with 10 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 fourth amended and restated credit agreement, or the credit facility, have been met.

Obligations under the credit facility are secured by substantially all of our assets and are guaranteed, except for certain subsidiaries, by the Partnership and each such subsidiary. The revolving loans mature at the maturity of the credit facility in August 2011. Interest on revolving loans thereunder will be calculated, at our option, at either: (a) a base rate that is the greater of (i) a base rate plus the applicable margin and (ii) a federal funds effective rate plus 0.50 percent plus the applicable margin, or (b) an adjusted LIBOR rate plus the applicable margin. The applicable margin that is used in calculating interest shall range from 0.50 percent to 1.25 percent for base rate loans and from 1.50 percent to 2.25 percent for Eurodollar loans. The weighted average interest rate for the revolving and term loan facilities, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs was 6.27 percent for the year ended December 31, 2008. We must pay (i) a commitment fee ranging from 0.300 percent to 0.500 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 1.50 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 us to maintain the ratios of debt to consolidated EBITDA and consolidated EBITDA to interest expense within certain threshold ratios. The credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursement of the Partnership for expenses and payment of distributions to the Partnership to the extent of our determination of available cash as defined in our partnership agreement (so long as no default or event of default has occurred or is continuing). The credit facility also contains certain other covenants.

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Credit Agreement Amendment. On February 26, 2009, RGS entered into Amendment Agreement No. 7 (the Amendment) with Wachovia Bank, National Association, as administrative agent, and the lenders party thereto in order to amend the Credit Agreement. The Amendment will become effective upon the closing of the Contribution Agreement of the joint venture and the satisfaction of certain other conditions precedent.

Upon its effectiveness, the Amendment, among other things, (a) authorizes the contribution by Regency HIG of its ownership interests in RIGS to the joint venture and future investments in the joint venture of up to $135,000,000 in the aggregate, (b) permits distributions by RGS to the Partnership in an amount equal to the outstanding loans, interest and fees under a $45,000,000 revolving credit facility with GECC entered into on February 26, 2009, (c) adds an additional financial covenant that limits the ratio of senior secured indebtedness to EBITDA, (d) provides for certain EBITDA adjustments in connection with the Haynesville Expansion Project, and (e) increases the applicable margins and commitment fees applicable to the credit facility, as further described below.

Upon the effectiveness of the Amendment, (a) 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 LIBOR rate for a borrowing with a one-month interest period plus 1.50 percent, (b) the applicable margin that is used in calculating interest shall range from 1.50 percent to 2.25 percent for base rate loans and from 2.50 percent to 3.25 percent for Eurodollar loans, and (c) commitment fees will range from 0.375 percent to 0.50 percent.

The Amendment prohibits RGS or its subsidiaries from allowing the joint venture to incur or permit to exist any preferred interests or indebtedness for borrowed money of the joint venture prior to the completion date of the Haynesville Expansion Project. RGS and GECC executed a side letter on February 26, 2009 confirming that, after the closing of the Contribution Agreement, they will not permit their representatives on the management committee of the joint venture to violate such restriction.

Revolving Credit Facility. On February 26, 2009, we entered into a $45,000,000 unsecured revolving credit agreement with GECC, as administrative agent, the lenders party thereto and the guarantors party thereto (the Revolving Credit Facility). The proceeds of the Revolving Credit Facility may be used for expenditures made in connection with the Haynesville Expansion Project prior to the earlier to occur of the effectiveness of the Amendment and April 30, 2009. The commitments under the Revolving Credit Facility will terminate automatically on the earlier to occur of the effectiveness of the Amendment and April 30, 2009, and the Partnership will be required to prepay all outstanding loans upon the effectiveness of the Amendment. The maturity date under the Revolving Credit Facility will be the earlier of the date that is three months after the final maturity date under the Credit Agreement and November 15, 2011.

Interest will be calculated, at our option, at either (a) the greater of (i) a federal funds effective rate plus 0.50 percent plus the applicable margin or (ii) an adjusted LIBOR rate for a borrowing with a one-month interest period plus 1.50 percent plus the applicable margin and (b) an adjusted LIBOR rate plus the applicable margin. The applicable margin that is used in calculating interest shall range from 3.00 percent to 10.00 percent for base rate loans and from 4.00 percent to 11.00 percent for Eurodollar loans. The Partnership shall pay a 6 percent origination fee. The Partnership shall pay a commitment fee of 0.75 percent per annum on the unused portion of the commitments under the Revolving Credit Facility.

We are required to comply with the covenants set forth in the Credit Agreement and in the Partnership s Indenture dated as of December 12, 2006 among us, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee. The Revolving Credit Facility is guaranteed by our subsidiaries (as defined in the Revolving Credit Facility) (other than RIGS, unless the Amendment does not become effective by April 30, 2009).

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Letters of Credit. At December 31, 2008, we had outstanding letters of credit totaling $16,257,000. The total fees for letters of credit accrue at an annual rate of 1.5 percent, which is applied to the daily amount of letters of credit exposure.

Senior Notes. In 2006, the Partnership and Finance Corp., a wholly owned subsidiary of RGS, issued, in a private placement, $550,000,000 in principal amount of senior notes that mature on December 15, 2013. The senior notes bear interest at 8.375 percent and interest is payable semi-annually in arrears on each June 15 and December 15, and are guaranteed by all of our subsidiaries. In August 2007, we redeemed 35 percent, or $192,500,000, of the aggregate principal amount of the senior notes with the net cash proceeds from our July 2007 equity offering and we paid an early redemption penalty of $16,122,000. In September 2007, the Partnership exchanged its then outstanding 8 3/8 percent senior notes which were not registered under the Securities Act of 1933 for senior notes with identical terms that have been so registered

The senior notes and the guarantees are unsecured and rank equally with all of our and the guarantors existing and future unsubordinated obligations. The senior notes and the guarantees are senior in right of payment to any of our and the guarantors future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees are effectively subordinated to our and the guarantors secured obligations, including our credit facility.

The senior notes are initially guaranteed by each of the Partnership s current subsidiaries (the Guarantors), except certain wholly owned subsidiaries. These note guarantees are the joint and several obligations of the Guarantors. No guarantor may sell or otherwise dispose of all or substantially all of its properties or assets if such sale would cause a default under the terms of the senior notes. Events of default include nonpayment of principal or interest when due; failure to make a change of control offer; failure to comply with reporting requirements according to SEC rules and regulations; and defaults on the payment of obligations under other mortgages or indentures.

We may redeem the 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 holder of senior notes will be entitled to require us to purchase all or a portion of its notes at a purchase price equal to 101 percent of the principal amount thereof, plus accrued and unpaid interest and liquidated damages, if any, to the date of purchase. 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 covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to: (i) incur additional indebtedness; (ii) pay distributions on, or repurchase or redeem equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into certain types of transactions with our affiliates; and (vi) sell assets or 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, 2008, we were in compliance with these covenants.

Equity Offering. On August 1, 2008, the Partnership sold 9,020,000 common units for an average price of $22.18 per unit. The Partnership received $204,133,000 in proceeds, inclusive of the General Partner s proportionate capital contribution of $4,082,653. As of December 31, 2008 the Partnership has incurred $34,000 in costs related this equity offering. An affiliate of GECC purchased 2,272,727 of these common units. The Partnership used the proceeds from its equity offering to repay a portion of its credit facility.

Off-Balance Sheet Transactions and Guarantees. We have no off-balance sheet transactions or obligations as of December 31, 2008.

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Operating Lease Facility. CDM entered into an operating lease facility with Caterpillar Financial Services Corporation whereby CDM has the ability to lease compression equipment with an aggregate value of up to $75,000,000. The facility is available for leases with inception dates up to and including December 31, 2009, and mitigates the need to use available capacity under the existing Credit Facility. Each compressor acquired under this facility shall have a lease term of one hundred twenty (120) months with a fair value buyout option at the end of the lease term. At the end of the lease term, CDM shall also have an option to extend the lease term for an additional period of sixty (60) months at an adjusted rate equal to the fair market rate at that time. In the event CDM elects not to exercise the buyout option, the equipment must be returned in a manner fit for use at the end of the lease term. In addition to the fair value buyout option at the end of the lease term, early buyout option provisions exist at month sixty (60) and at month eighty four (84) of the one hundred twenty (120) month lease term. Covenants under the lease facility require CDM to maintain certain fleet utilization levels as of the end of each calendar quarter as well as a total debt to EBITDAR (Earnings Before Interest, Taxes, Depreciation, Amortization, and Rental expense) ratio of less than or equal to 4:1. In addition, covenants restrict the concentration of revenues derived from the equipment acquired under the lease facility. The terms of the lease facility do not include contingent rentals or escalation clauses.

Total Contractual Cash Obligations. The following table summarizes our total contractual cash obligations as of December 31, 2008.

	Payment Due by Period				
	Total	**2009**	**2010-2011**	**2012-2013**	**Thereafter**
			(in thousands)		
Long-term debt (including interest)[1]	$ 1,217,870	$ 53,433	$ 747,056	$ 417,381	$
Capital leases	10,099	612	1,015	910	7,562
Operating leases	15,490	2,357	4,874	2,786	5,473
Purchase obligations	323,341	320,321	3,020		
Total[2][3]	$ 1,566,800	$ 376,723	$ 755,965	$ 421,077	$ 13,035

(1) Assumes a constant LIBOR interest rate of 2.0 plus applicable margin (1.5 percent as of December 31, 2008) for our revolving credit facility. The principal of our outstanding senior notes ($357,500,000) bears a fixed rate of 8 3/8 percent.

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

(3) Excludes deferred tax liabilities of $8,156,000 as the amount payable by period can not be readily estimated in light of 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 will not have a material adverse effect on our business, financial condition and results of operations.

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

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.

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We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

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.

Risk Management Activities. In order to protect ourselves from commodity price risk, we pursue hedging activities to minimize those risks. These hedging activities rely upon forecasts of our expected operations and financial structure over the next three years. If our operations or financial structure are significantly different from these forecasts, we could be subject to adverse financial results as a result of these hedging activities. We mitigate this potential exposure by retaining an operational cushion between our forecasted transactions and the level of hedging activity executed. We monitor and review hedging positions regularly.

Effective July 1, 2005, we elected hedge accounting under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended, and determined the then outstanding hedges, excluding crude oil put options, qualified for hedge accounting. Accordingly, we recorded the unrealized changes in fair value in other comprehensive income (loss) to the extent the hedge are effective. Effective June 19, 2007, we elected to account for our entire outstanding commodity hedging instruments on a mark-to-market basis except for the portion of commodity hedging instruments where all NGLs products for a particular year were hedged and the hedging relationship was effective. As a result, a portion of our commodity hedging instruments is and will continue to be accounted for using mark-to-market accounting until all NGLs products are hedged for an individual year and the hedging relationship is deemed effective.

Purchase Method of Accounting. We make various assumptions in determining the fair values of acquired assets and liabilities. In order to allocate the purchase price to the business units, we develop fair value models with the assistance of outside consultants. These fair value models apply discounted cash flow approaches to expected future operating results, considering expected growth rates, development opportunities, and future pricing assumptions. An economic value is determined for each business unit. We then determine the fair value of the fixed assets based on estimates of replacement costs. Intangible assets acquired consist primarily of licenses, permits and customer contracts. We make assumptions regarding the period of time it would take to replace these licenses and permits. We assign value using a lost profits model over that period of time necessary to replace the licenses and permits. We value the customer contracts using a discounted cash flow model. We determine liabilities assumed based on their expected future cash outflows. We record goodwill as the excess of the cost 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.*The Partnership reviews the carrying value of goodwill on a regular basis, including December 31 of each year, for indicators of impairment at each reporting unit that has recorded goodwill. The Partnership determines its 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, the Partnership estimates 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. The estimates of fair value of these reporting units could change if actual volumes, prices, costs or expenses vary from these estimates.

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Based on the Partnership s annual impairment testing on December 31, 2008, no impairment was identified. If current credit issues and market volatility continue to deteriorate, the Partnership s goodwill could be impaired and have a material impact on future earnings of the Partnership.

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. Options granted were valued using the Black-Scholes option pricing model, using assumptions of volatility in the unit price, a ten year term, a strike price equal to the grant-date price per unit, a distribution per unit at the time of grant, a risk-free rate, and an average exercise of the options of four years after vesting is complete. We have based the assumption that option exercises, on average, will be four years from the vesting date on the average of the mid-points from vesting to expiration of the options. There have been no option awards made subsequent to the GE EFS Acquisition.

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 as described in SFAS No. 141, Business Combinations. 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 acquiree s assets and liabilities. In common control acquisitions where a minority interest is also acquired, we use the purchase method of accounting for the minority interest. Further, certain transaction costs that would normally be capitalized are expensed.

Fair Value Measurements. On January 1, 2008, we adopted the provisions of SFAS No. 157 for financial assets and liabilities. SFAS No. 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations. SFAS No. 157 establishes 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 markets accessible by us;

Level 2 inputs that are observable in the marketplace other than those inputs classified as Level 1; and

Level 3 inputs that are unobservable in the marketplace and significant to the valuation.

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SFAS No. 157 encourages us to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument valuation uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation. Our financial assets and liabilities measured at fair value on a recurring basis are derivative financial instruments consisting of interest rate swaps and commodity swaps.

The Partnership s financial assets and liabilities measured at fair value on a recurring basis are risk management assets and liabilities related to interest rate and commodity swaps. Risk management assets and liabilities 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. The Partnership has no financial assets and liabilities as of December 31, 2008 valued based on inputs 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 has 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 exposed to the impact of market fluctuations in the prices of natural gas, NGLs, and other commodities as a result of our gathering, processing and marketing activities, which in the aggregate produce a naturally long position in both natural gas and NGLs. We attempt to mitigate commodity price risk exposure by matching pricing terms between our purchases and sales of commodities. To the extent that we market commodities in which pricing terms cannot be matched and there is a substantial risk of price exposure, we attempt to use financial hedges to mitigate the risk. It is our policy not to take any speculative marketing positions. 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.

Both our profitability and our cash flow are affected by volatility in prevailing natural gas and NGL prices. Natural gas and NGL prices are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. Adverse effects on our cash flow from reductions in natural gas and NGL product prices could adversely affect our ability to make distributions to 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 our areas of operations, and the use of derivative contracts.

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We are a net seller of NGLs, natural gas and condensate, and as such our financial results are exposed to fluctuations in commodity pricing. We have executed swap contracts settled against condensate, ethane, propane, butane, natural gas, and natural gasoline market prices. We have hedged our expected exposure to decline in prices for NGLs and condensate volumes produced for our account in the approximate percentages set for below:

	2009	2010
NGL	97%	33%
Condensate	76%	76%
Natural gas	63%	0%

We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

In March 2008, the Partnership entered offsetting trades against its existing 2009 portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its existing 2009 hedges. This group of trades, along with the pre-existing 2009 portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated under SFAS No. 133 as cash flow hedges.

In May 2008, the Partnership entered into one-year commodity swaps to hedge its 2010 NGL commodity risk, except for ethane, which are accounted for using mark-to-market accounting. We chose to delay hedging our 2010 exposure to ethane due to our perception that the prices offered by the counterparties were sharply discounted from comparable forward crude prices. We expect to hedge our ethane exposure in the future.

The Partnership accounts for a portion of its 2008 and all of its 2009 West Texas Intermediate crude oil swaps using mark-to-market accounting. In May 2008, the Partnership entered into a one-year West Texas Intermediate crude oil swap to hedge its 2010 condensate risk, which was designated as a cash flow hedge in June 2008.

The following table sets forth certain information regarding our non-trading NGL swaps outstanding at December 31, 2008. 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).

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive		Fair Value Asset/(Liability) (in thousands)	
January 2009-December 2009	Ethane	701	(MBbls)	Index	$0.80	($/gallon)	$	10,827
January 2009-December 2010	Propane	694	(MBbls)	Index	$0.9815 - $1.5325	($/gallon)		16,726
January 2009-December 2010	Iso Butane	157	(MBbls)	Index	$1.685 - $1.915	($/gallon)		6,172
January 2009-December 2010	Normal Butane	299	(MBbls)	Index	$1.166 - $1.895	($/gallon)		7,737
January 2009-December 2010	Natural Gasoline	310	(MBbls)	Index	$1.4975 - $2.53	($/gallon)		14,033
January 2009-December 2010	West Texas Intermediate Crude	475	(MBbls)	Index	$68.17 - $121.30	($/Bbl)		16,650
January 2009-December 2010	Natural Gas	3,650,000	(MMBtu)	Index	$6.67 - $6.705	($/MMBtu)		2,134
January 2009-March 2010	Interest Rate	$ 300,000,000		2.40%	One-month	LIBOR		(5,239)
Credit risk adjustment	Credit risk adjustment							(1,500)
					Total Fair Value		$	67,540

Credit Risk. Our purchase and resale of natural gas exposes 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.

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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, 2008, 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, 2008, we had $468,729,000 of outstanding long-term balances exposed to variable interest rate risk. An increase of 100 basis points in the LIBOR rate would increase our annual payment by $4,687,000. On February 29, 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (1.5 percent as of December 31, 2008) through March 5, 2010. These interest rate swaps were designated as cash flow hedges in March 2008.

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

On June 18, 2007, Deloitte & Touche LLP (Deloitte) advised the Partnership that, in light of the change of control from HM Capital to GE EFS and because of existing relationships with GE, effective as of the date of the change of control of the Partnership, Deloitte would no longer be able to serve as the Partnership s independent registered public accounting firm because it would no longer satisfy the independence requirements necessary to certify the financial statements of the Partnership. As a result, Deloitte resigned as the Partnership s independent registered public accounting firm, effective as of June 18, 2007.

Deloitte has expressed an unqualified opinion on the consolidated financial statements of the Partnership for the years ended December 31, 2006 and 2005. Such opinion included an explanatory paragraph related to the Partnership s accounting for its acquisition of TexStar as entities under common control in a manner similar to a pooling of interests. During the two most recent fiscal years and interim period preceding Deloitte s resignation, there were no disagreements with Deloitte and no reportable events as defined under Item 304(a)(1)(v) of Regulation S-K. A copy of Deloitte s letter dated June 18, 2007 is incorporated by reference as Exhibit 16.1.

On June 18, 2007, the Board of Directors of the General Partner, subject to approval of the engagement terms by the Audit Committee, requested KPMG LLP (KPMG) to act as the independent registered public accounting firm in auditing the financial statements of the Partnership for the year ending December 31, 2007 and in performing such other attestation services for the Partnership as may be required for the remainder of calendar year 2007. On June 26, 2007, the Audit Committee of the Partnership approved the engagement terms of KPMG and authorized KPMG to serve as the Partnership s independent registered public accountants for the fiscal year ending December 31, 2007.

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

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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 assurances 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, 2008.

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, as amended.

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 generally accepted accounting principles 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 generally accepted accounting principles, 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, 2008. In making this assessment, management used the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of

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the Treadway Commission (the COSO Framework). 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.

On January 15, 2008, the Partnership acquired CDM. Management has acknowledged that it is responsible for establishing and maintaining a system of internal controls over financial reporting for CDM. The Partnership excluded CDM from its December 31, 2008 assessment of the effectiveness of internal controls over financial reporting. The Partnership initiated in early 2008 a program of documentation, implementation and testing of internal control over financial reporting for CDM. This program will continue throughout this year, culminating with the sub-certification and attestation by CDM management to the Partnership s senior management in support of the Partnership s Section 404 certification and attestation in early 2010. The impact of the acquisition of CDM has not materially affected and is not expected to materially affect the Partnership s internal control over financial reporting. As a result of these integration activities, certain controls will be evaluated and they may be changed. The Partnership believes, however, it will be able to maintain sufficient controls over the substantive results of its financial reporting throughout this integration process.

CDM had total assets of $881,552,000 and total external revenues of $132,549,000 included in the consolidated financial statements of Regency Energy Partners LP as of and for the year ended December 31, 2008.

Based on its assessment, management has concluded that the Partnership s internal control over financial reporting was effective as of December 31, 2008.

(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 year 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.

Item 9B. Other Information

None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management. Our General Partner manages and directs all of our activities. Our officers and directors are officers and directors of the General Partner. The owner of the General Partner may appoint up to ten persons to serve on the Board of Directors of the General Partner. Although there is no requirement that he do so, the President and Chief Executive Officer of the General Partner is currently a director of the General Partner and serves as Chairman of the Board of Directors.

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 401 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

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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 relating to our audited financial statements.

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.

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.

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Name	Age	Position with Regency GP LLC
Byron R. Kelley	61	Chairman of the Board, President and Chief Executive Officer
Patrick Giroir	47	Chief Commercial Officer for Gathering and Processing and Transportation segments
Stephen L. Arata	43	Executive Vice President and Chief Financial Officer
Randall H. Dean	53	President and Chief Executive Officer for Contract Compression segment
Dan Fleckman	67	Executive Vice President, Chief Legal, and Administrative Officer and Secretary
Lawrence B. Connors	57	Senior Vice President, Finance and Accounting and Chief Accounting Officer
Christofer D. Rozzell	32	Senior Vice President, Development and Strategic Planning
Dennie W. Dixon	61	Senior Vice President, of Operations for Gathering and Processing and Transportation Segments
Shannon A. Ming	32	Vice President, Investor Relations and Communications
James M. Richter	56	Vice President, Human Resources
Houston C. Ross III	39	Vice President, Financial Analysis and Planning
A. Troy Sturrock	38	Vice President, Controller
Ramon Suarez, Jr.	46	Vice President, Treasurer
Michael J. Bradley(1)(2)(4)	54	Director
James F. Burgoyne(1)	50	Director
Daniel R. Castagnola(5)(6)	42	Director
Rodney L. Gray(2)(3)	56	Director
Paul Halas(4)(6)	52	Director
Mark T. Mellana(4)(5)	44	Director
John T. Mills(2)(3)(5)	61	Director
Brian P. Ward(1)	49	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.

Patrick Giroir was elected Chief Commercial Officer for the Gathering & Processing and Transportation Segments of Regency GP LLC November 2008. From May 2008 through November 2008, Mr. Giroir served as Senior Vice President of Strategy and Special Projects of Regency. 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. In addition, Mr. Giroir is a CPA.

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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.

Randall H. Dean has served as President and Chief Executive Officer of CDM Resource Management LLC since January 15, 2008. Previously, Mr. Dean served as President and Chief Executive Officer of CDM Resource Management, Ltd. since co-founding it in 1997. Mr. Dean has over twenty years of experience in the natural gas compression industry.

Dan Fleckman was elected Executive Vice President, Chief Legal and Administrative Officer and Secretary of Regency GP LLC in May 2008. Mr. Fleckman has extensive experience in private practice and corporate executive legal positions, representing publicly and privately held companies in corporate finance, corporate governance, mergers and acquisitions, and strategic alliances. Prior to joining Regency, Mr. Fleckman was a partner in the law firm of Vinson & Elkins LLP since June 2000 and previously a partner at the law firm of Andrews Kurth. Mr. Fleckman is a member of the American Bar Association.

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.

Christofer D. Rozzell was elected Senior Vice President, Development and Strategic Planning of Regency GP LLC in November 2008. From June 2005 to November 2008, Mr. Rozzell served in various roles at Regency GP LLC, most recently as Vice President of Corporate Development. From May 2001 to May 2005, Mr. Rozzell held managerial positions in the strategic planning and enterprise risk groups of TXU Corp., which generates, transmits, and distributes electricity to customers in Texas. Mr. Rozzell has experience in the investment banking industry, focusing on mergers and acquisitions and financings across multiple industries.

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. Dixon retired from El Paso after 33 years of service in 2004.

Shannon A. Ming was elected Vice President, Investor Relations and Communications of Regency GP LLC in February 2008. Mrs. Ming joined Regency GP LLC in April, 2006 as Director of Investor Relations. From August 2001 to March 2006, Mrs. Ming served in various capacities with TXU Corp., which generates, transmits, and distributes electricity to customers in Texas. Mrs. Ming s responsibilities included managerial positions in strategic planning, product development and marketing.

James M. Richter was elected Vice President, Human Resources in June 2007. From January 2007 to June 2007, Mr. Richter served as the human resources manager at Regency GP LLC. From October 2005 to August

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2006, Mr. Richter worked for USAA, which offers insurance, banking, and investment services, as Senior People Officer. From June 2001 to August 2005, Mr. Richter was employed by Argonaut Group, Inc., an insurance underwriter, as Vice President, Human Resources. Mr. Richter has held various senior management positions at companies in the energy sector.

Houston C. Ross III was elected Vice President of Financial Analysis and Planning of Regency GP LLC in March 2007. From February 2004 until March 2007, Mr. Ross served as Director of Financial Analysis and Planning for Regency Gas Services LP and its predecessor. From February 2003 until February 2004, Mr. Ross worked for Energy, Economic, and Environmental Consultants, Inc., as a Senior Economic Analyst specializing in natural gas royalty litigation support.

A. Troy Sturrock was elected Vice President, Controller of Regency GP LLC in February 2008. From June 2006 to February 2008, Mr. Sturrock served as the Assistant Controller and Director of Financial Reporting and Tax for Regency GP LLC. From January 2004 to June 2006, Mr. Sturrock was associated with the Public Company Accounting Oversight Board, where he was an inspection specialist in the division of registration and inspections. Mr. Sturrock served in various roles at PricewaterhouseCoopers LLP from 1995 to 2004, most recently as a senior manager in the audit practice specializing in the transportation and energy industries. Mr. Sturrock is a Certified Public Accountant.

Ramon Suarez, Jr. was elected Vice President, Treasurer of Regency GP LLC in March 2007. From February 2006 to March 2007, Mr. Suarez was Director of Treasury for Regency GP LLC. Mr. Suarez worked for CompUSA, a computer retailer, as Director of Corporate Finance from March 1999 to December 2005. Mr. Suarez has over 21 years of financial experience.

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.

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.

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.

Rodney L. Gray was elected to the Board of Directors of Regency GP LLC on February 22, 2008. Since 2003, Mr. Gray has served as chief financial officer of Colonial Pipeline, an interstate carrier of petroleum products.

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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.

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.

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 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.

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.

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 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 during the fiscal year ended December 31, 2008 our General Partner s officers, directors and greater than 10 percent common unitholders filed all reports they were required to file under Section 16(a).

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Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

Overview of Our Executive Compensation Program

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

- Byron R. Kelley, President, Chief Executive Officer and Chairman of the Board
- James W. Hunt, former President, Chief Executive Officer and Chairman of the Board
- Stephen L. Arata, Executive Vice President and Financial Officer
- Dan A. Fleckman, Executive Vice President, Chief Legal Officer, and Secretary
- Randall H. Dean, President and Chief Executive Officer for the Contract Compression Segment
- Richard D. Moncrief, former Executive Vice President and Chief Operating Officer
- Lawrence B. Connors, Senior Vice President, Finance and Accounting and Chief Accounting Officer

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 our business s short- and long-term goals. To do this, our compensation program is made up 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) equity awards, meant to align 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 company 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 Named Executive Officers.

The Committee is charged, among other things, with the responsibility of reviewing the executive officer compensation policies and practices to ensure (a) adherence to the 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 LTIP awards in the form of equity-based restricted units, as well as other customary employment benefits. Total compensation of executive officers and the relative emphasis of the three main components of annual compensation are reviewed and established on an annual basis by the Committee.

At the beginning 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 be greater than, the projections of the anticipated performance of the Partnership provided 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 one or more meetings, for several purposes. These include (a) assessing the performance of the CEO and other senior officers with respect to the Partnership results for the

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prior 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.

In addition, the Committee, at these meetings and after taking into account both the advice of outside consultants and recommendations of senior management, sets base salary levels and target bonus levels (representing the bonus that may be awarded expressed as a percentage of base salary for the year) for executive officers. The Committee also considers recommendations to be made to the Board regarding awards to executive officers, as well as other employees, under the LTIP for the ensuing fiscal year.

Compensation Philosophy & 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. A further objective is to provide incentives to and to reward our executive officers and key employees for positive contributions to our business and operations, and to align their interests with our unitholders interests.

In setting the 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 holdings to align the interests of executive officers and key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship, cooperation among business units and employee pay.

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

In measuring the contributions of our executive officers and the performance of the Partnership, the Committee considers a variety of financial measures, including the non-GAAP financial measures of adjusted EBITDA, cash available for distribution, adjusted segment margin, and adjusted total segment margin, all of which are used by management as key measures of the Partnership s financial performance. The most important of these are (a) adjusted EBITDA, which we define as net income (loss) plus net interest expense, depreciation and amortization expense, unrealized loss (gain) from risk management activities, non-cash commodity put option expirations and loss on debt refinancing, and (b) cash available for distribution. The Committee also considers total unitholder return, which includes both appreciation in market value of our common units and the amount of distributions paid with respect to all our outstanding units. In addition, the Committee takes into account a variety of factors related to individual performance. The Committee believes that the measures outlined above best define the performance of the Partnership.

Market Analysis

In 2008, to ensure that our compensation practices are 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 twenty publicly-traded limited partnerships listed below, that are in the mid-stream market 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. Our peer group consists of the following group of companies:

Atlas Pipeline Partnerships LP	Holly Energy Partners LP
Boardwalk Pipeline Partners, LP	Magellan Midstream Partners LP
Buckeye Partners LP	Markwest Energy Partners LP
Copano Energy LLC	Martin Midstream Partners LP
Crosstex Energy LP	Nustar Energy LP
DCP Midstream Partners LP	Plains All American Pipeline LP
Eagle Rock Energy Partners LP	Quicksilver Gas Services LP
Energy Transfer Partners LP	Sunoco Logistics Partners LP
Enterprise Products Partners LP	Targa Resources Partners LP
Hiland Partners LP	Teppco Partners LP

In addition to our peer group, we also rely on the expertise of our compensation consultant, BDO Seidman, who uses confidential and proprietary surveys in order to obtain a more complete picture of the overall compensation environment.

When considering the data, the Committee generally targets each component of compensation to 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 increases 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.

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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 performance; targeted over time 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 corporate objectives and individual performance against target performance levels; targeted to approximate the 50th 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 direct compensation; potential for lesser or greater amounts are intended to motivate executives to achieve or exceed our financial and operational goals; no rewards are paid if performance goals are not met.
Equity based awards (restricted units)	Performance-based equity awards granted at the discretion of the Committee. Awards are based on performance of the Partnership and competitive practices at peer companies. Grants typically vest ratably over four years and are eligible for distribution payments.	Align interest of executive officers with unitholders; motivate and reward executive officers to increase unitholder value over the long term. Ratable vesting over a four year period will facilitate retention of executive officers.
Equity based awards (Class C Units)	Class C units are a separate class of securities representing an economic interest in our General Partner. These units are structured as management incentive equity and vest based on performance attributable to achieving 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 ($15,500 for 2008) The Partnership matches $1 for $1 up to 6 percent of eligible compensation.	Provide employees with the opportunity to save for their future retirement.
Health & welfare benefits	Health & 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.

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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 company, changes to the individual s position within the company, 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 chairman of the Committee.

2008 Fiscal Year Results. Effective as of March 31, 2008, the Committee made the following decisions with respect to salary adjustments:

- Mr. Hunt: no salary increase, due to his resignation;
- Messrs. Arata and Connors: base salaries were increased to $275,000 (10 percent) and $190,000 (5 percent), respectively. Their salary increases matched or lagged the marketplace;
- Mr. Moncrief: base salary was increased to $325,000 (18 percent). His salary increase reflected his promotion to Chief Operations Officer;
- Messrs. Kelley, Fleckman and Dean: as new hires in 2008, received base salaries of $475,000, $225,000 and $316,900, respectively. Compensation decisions for Messrs. Kelley, Fleckman, and Dean were the result of negotiations in a competitive environment. In making base salary decisions for them, we took into account the position that each would fill, the potential value that each would provide to the Partnership, the compensation that each earned in his prior employment, and our desire to incentivize them to join our Partnership.

While our stated goal is to approximate the salaries of the 50th percentile of our peer group of companies, we believe that it is important, in some cases, to deviate from in order to attract the best talent for critical positions within our company. As a result, the base salaries of Messrs. Kelley and Dean are closer to the 75th percentile of base salary compensation that our peer companies pay to executives with similar positions and responsibilities.

Changes for Fiscal Year 2009. At its meeting in February 2009, the Committee discussed salary data for our comparator group, our annual performance targets for individual officers, and general economic conditions and challenges facing the Company in this fiscal year. The Committee decided to defer base salary considerations for the NEOs until mid-year.

Annual Incentive Bonuses

Design. Annual incentive bonuses are targeted at market median levels. 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 his base salary. To arrive at a payout amount, 80 percent of bonus opportunity is based on the achievement of corporate performance goals and 20 percent is based on the Committee s subjective evaluation of each Named Executive Officer s individual performance. However, the determination of any actual amounts paid out under this plan is subject to the Committee s discretion.

For 2008, the Committee established the following corporate performance objectives:

Adjusted EBITDA defined as net income (loss) plus net interest expense, depreciation and amortization expense, unrealized loss (gain) from risk management activities, non-cash commodity put option expirations, and loss on debt refinancing;

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Segment Adjusted EBITDA depending on the Named Executive Officer, achievement of Segment Adjusted EBITDA is tied to performance of either our gathering, processing and transportation segments or contract compression segment; and

Cash distributed on a per unit basis.

Each of these performance metrics is equally weighted and is subject to a threshold, target and stretch performance goal. If threshold performance is achieved, no portion of the bonus opportunity that is attributable to company performance will be paid. If target performance is achieved for each metric, then 80 percent of the bonus opportunity may be paid. If stretch performance is achieved, then the Committee has the discretion to apply a 3x multiplier to the target payout amount, resulting in the potential to be paid up to 240 percent of bonus opportunity. Annual incentive bonuses are prorated if actual performance falls between the defined threshold and stretch corporate performance targets. For 2008, the corporate performance targets were as follows:

Performance Metric	Threshold	Target	Stretch
Adjusted EBITDA (millions)	$ 230	$ 242	$ 262
Segment Adjusted EBITDA			
Gathering/Processing/Transportation (millions)[1]	154	165	185
Compression (millions)[2]	51.6	55.7	62.5
Per Unit Cash Distributions	1.64	1.74	1.90

1 In evaluating the bonus opportunity for Segment Adjusted EBITDA performance, the bonus opportunity for Messrs. Kelley, Arata, Fleckman and Connors is calculated only with regard to the Gathering and Processing and Transportation Segments. Segment Adjusted EBITDA excludes the operating results of FrontStreet.

2 In evaluating the bonus opportunity for Segment Adjusted EBITDA performance, the bonus opportunity for Mr. Dean is calculated only with regard to the Contract Compression Segment.

For 2008, approximately 20 percent of the bonus opportunity is dependent on the Committee s subjective assessment of each Named Executive Officer s individual performance. 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. Based on the CEO s review of each Named Executive Officer s performance, each officer is then assigned a numerical performance rating. However, any amounts awarded based on individual performance are subject to the Committee s discretion.

The following table describes each Named Executive Officer s bonus opportunity, calculated as a percentage of base salary.

	2008 Annual Incentive Bonus Opportunity as a % of Salary		
Named Executive Officer	Threshold Performance	Target Performance	Maximum Performance
Byron R. Kelley	0%	100%	3 x Target Performance Award
James W. Hunt	Ineligible	Ineligible	Ineligible
Stephen L. Arata	0%	75%	3 x Target Performance Award
Dan A. Fleckman	0%	75%	3 x Target Performance Award
Randall H. Dean	0%	100%	3 x Target Performance Award
Lawrence B. Connors	0%	75%	3 x Target Performance Award
Richard Moncrief	Ineligible	Ineligible	Ineligible

The Committee, in its sole authority, retains the right to apply an additional discretionary multiplier to any or all bonus awards. This discretionary multiplier ranges from zero to two times eligible bonus award and allows the Committee broader discretion in achieving pay for performance objectives. This discretionary multiplier is

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meant to reward extraordinary corporate performance or extraordinary individual contributions to the achievement of corporate or individual performance targets. In 2008, the Committee chose to apply a discretionary multiplier to reduce bonus awards to approximate target levels.

Fiscal Year 2008 Results. The following chart shows our 2008 actual financial results:

Performance Metric	Financial Results	
Adjusted EBITDA (millions)	$	254.5
Segment Adjusted EBITDA		
Gathering/Processing/Transportation (millions)(1)	$	175.8
Contract Compression (millions)(2)	$	58.7
Per Unit Cash Distributions	$	1.755

(1) In evaluating the bonus opportunity for Segment Adjusted EBITDA performance, the bonus opportunity for Messrs. Kelley, Arata, Fleckman and Connors is calculated only with regard to the Gathering and Processing and Transportation Segments. Segment Adjusted EBITDA excludes the operating results of FrontStreet.

(2) In evaluating the bonus opportunity for Segment Adjusted EBITDA performance, the bonus opportunity for Mr. Dean is calculated only with regard to the Contract Compression Segment.

The Partnership exceeded the corporate performance target for each performance metric, which created a bonus opportunity of 180 percent of base salary for Messrs. Kelly, Arata, Fleckman and Connors, and a bonus opportunity of 173 percent for Mr. Dean. However, as a result of current economic conditions and the Partnership s desire to reduce cash outlays and limit expenses, including compensation expenses, the Committee exercised its discretion to limit bonus awards to approximate target levels.

Named Executive Officer	Annual Incentive Bonus Award as a% of Salary
Byron R. Kelley(1)	84%
James W. Hunt	N/A
Stephen L. Arata(2)	76%
Dan A. Fleckman(3)	50%
Randall H. Dean	100%
Lawrence B. Connors(2)	74%
Richard Moncrief	N/A

(1) Mr. Kelley s annual bonus award was determined in compliance with the terms of his employment contract, which guaranteed him a $400,000 bonus.

(2) The Committee, in its discretion, made slight adjustments to Mr. Arata s and Mr. Connors bonus awards.

(3) The Committee prorated Mr. Fleckman s bonus award to account for his May 1, 2008 start date.

Changes for Fiscal Year 2009.

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 2009. 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 initial public offering 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.

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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.

Restricted Units. The only awards made under the LTIP in 2008 were restricted units. Restricted units so awarded may not be sold until vested, and unvested restricted units will be forfeited at the time the holder terminates employment. In general, restricted units awarded under our LTIP vest as to one-fourth of the award on each of the first four anniversaries of the date of the award. Restricted units participate in distributions on the same basis as other common units.

Class C Units. Class C Units 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 GE EFS and will be available for reissuance.

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 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.

2008 Fiscal Year Results. As a result of the availability of a limited number of units remaining available for grant under our LTIP, we made very few grants of equity awards to our employees during 2008. With respect to our named executive officers, we granted equity only to Messrs. Kelley and Fleckman in connection with our employment of them. Mr. Kelley was granted (a) 106,300 restricted units, with 56,300 units vesting in equal increments on the second and fourth anniversary of the grant date of the award and the remaining 50,000 units vesting ratably over four years and (b) 85 Class C Units representing 10.7 percent of the pool of such units. Mr. Fleckman was granted (a) 75,000 restricted units, which vest ratably over 4 years and (b) 50 Class C Units representing 6.3 percent of the pool of such units. While our goal is to target the market median of our peer group for equity compensation, we believe that it is appropriate to deviate from that range of compensation to recruit key individuals and to align their interests with long-term interests of the Partnership. We recognized that equity compensation would be a significant factor in negotiations with these individuals who were leaving behind significant compensation packages at their prior places of employment. These equity awards were important tools for compensating our new hires for the value they were leaving behind. These awards placed the Partnership in the range of the 75th percentile of our peer companies and we believe they were appropriate in light of the Partnership s investment in individuals that we believe are key to our long-term strategy.

Changes for Fiscal Year 2009. At its meeting in February 2009, the Committee did not make any material changes to long-term compensation for fiscal year 2009.

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

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participate in our tax-deferred 401(k) savings plan. The plan allows executive officers to defer compensation for retirement up to IRS imposed limits ($15,500 for 2008). The Partnership matches $1 for $1 up to 6 percent of eligible compensation. Decisions regarding this element of compensation do not impact any other element of compensation.

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.

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. In particular, we entered into a consulting services agreement with Mr. Hunt in connection with his retirement. In exchange for management consulting and advisory services from April 1 to December 31, 2008, we agreed to pay Mr. Hunt $33,500 per calendar month, the equivalent of his annualized base salary on a monthly basis. In connection with Mr. Moncrief s resignation and his agreement to provide us with management consulting and advisory services, we entered into a resignation and release agreement with him under which we paid him a lump sum payment of $262,250, the amount of which was determined through negotiations. 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 the GE EFS s Acquisition in June 2007, certain members of our management team received Class B membership interests in the Company. 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 Company. 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.

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, 2008 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

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COMPENSATION TABLES AND NARRATIVES

Summary Compensation Table for 2008

Name and Principal Position	Year	Salary ($)	Stock Awards ($)(2)	Option Awards ($)(2)	Non Equity Incentive Plan Compensation ($)	All Other Compensation ($)(4)(5)	Total ($)
Byron R. Kelley(1)	2008	356,250	249,118		400,000	72,189(3)	1,077,557
	2007						
President, Chief Executive Officer and Chairman of the Board	2006						
James W. Hunt(6)	2008	100,000					100,000
	2007	400,000		79,954		9,334	489,288
Former President, Chief Executive Officer and Chairman of the Board	2006	386,667		35,046	10,000	7,600	439,313
Stephen L. Arata	2008	268,750			208,200	10,029	486,979
	2007	250,000		27,987	127,875	10,324	416,186
Executive Vice President and Chief Financial Officer	2006	245,833		12,266	6,250	6,250	270,599
Dan A. Fleckman(1)	2008	150,000	339,578		112,800	6,012	608,390
	2007						
Chief Legal Officer, Executive Vice President and Secretary	2006						
Randall H. Dean(1)	2008	303,696			316,000	16,922	636,618
	2007						
President and Chief Executive for the Contract Compression Segment	2006						
Lawrence B. Connors	2008	187,500	79,166		140,500	8,792	415,959
	2007	180,000	40,665	12,004	55,800	8,450	296,919
Chief Accounting Officer and Senior Vice President	2006	176,000		5,246	4,500	750	186,496
Richard D. Moncrief(6)	2008	271,875				272,591	544,466
	2007	237,500	1,814,660	43,584	187,550	50,115	2,333,409
Former Executive Vice President and Chief Operating Officer	2006	145,513	269,840	13,916	5,000	1,500	435,769

(1) The amount under Salary reflects a pro rata portion of salary for Messrs. Kelley, Fleckman, and Dean, who began employment with the Partnership on April 1, 2008, May 1, 2008, and January 15, 2008, respectively.

(2) The amount included in the Stock Awards and Option Awards columns reflect the dollar amount of compensation expense recognized with respect to these in accordance with SFAS No. 123R for the years ended December 31, 2008, 2007 and 2006. The material terms of our outstanding LTIP awards to our executive officers are described in Compensation Discussion and Analysis-Components of Compensation-Equity Based Awards. No compensation is attributable to Class C units. The material terms of our Class C units are described in Compensation Components and Analysis, Equity-Based Awards, Class C Units.

(3) The amount includes payments of $41,539 and $15,851 for living and moving expenses, respectively.

(4)

The amount includes the Partnership contribution on behalf of the named executive officer to its 401(k) plan. The contribution basis for our executives is the same basis as all other employees of the Partnership.

(5) The Partnership did not provide perquisites or other personal benefits to any named executive officer exceeding $10,000.

(6) Messrs. Hunt and Moncrief each resigned from his position on April 1, 2008 and November 14, 2008, respectively.

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Grant of Plan Based Awards

The following table provides information concerning each grant to our NEOs in the year ended December 31, 2008.

Grants of Plan-Based Awards

For the Year Ended December 31, 2008

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold ($)	Target ($)	Maximum ($)	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock Awards ($)
Byron R. Kelley	3/17/2008	0	475,000	1,235,000	106,300	2,825,454
James W. Hunt						
Stephen L. Arata		0	206,500	536,900		
Dan A. Fleckman	5/01/2008	0	168,750	438,750	75,000	2,025,000
Randall H. Dean		0	316,900	823,940		
Lawrence B. Connors		0	142,500	370,500		
Richard D. Moncrief						

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 2008.

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 written prior notice of non-renewal. Mr. Kelley s annual base salary is $475,000, 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 2008 of $400,000 and for 2009 of $200,000 regardless of any performance criteria achieved. The agreement also entitled Mr. Kelley to a grant of 106,300 restricted units, the terms of which are discussed above in Compensation Discussion and Analysis Compensation Components and Analysis Equity-Based Awards 2008 Fiscal Year Results.

Mr. Kelley was also awarded 85 Class C Units of GP Acquirer, an indirect subsidiary of GECC. 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.

James W. Hunt: At the time of his employment by Regency Gas Services LLC on December 1, 2004, James W. Hunt, President and Chief Executive Officer, entered into an employment agreement with Regency Gas Services LLC. The agreement provided for a term of three years, a base salary of $240,000, participation by Mr. Hunt in the LTIP and other benefit plans adopted by the employer. This agreement was assigned by Regency Gas Services LLC to the Partnership.

In conjunction with his resignation, Mr. Hunt entered into a consulting services agreement dated April 1, 2008. The agreement specified that Mr. Hunt would perform any and all management consulting and advisory services from time to time through the period of December 31, 2008. Mr. Hunt was paid a rate of $33,500 per

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calendar month, commencing with the month of April 2008. The agreement also effectively terminated Mr. Hunt s employment agreement.

Dan A. Fleckman: On May 1, 2008. Regency GP LLC entered into a severance agreement with Mr. Fleckman. The term of the agreement extends through May 1, 2011. For additional information regarding the material terms of this agreement, please see the narrative below entitled Potential Payments Upon a Termination or Change in Control.

Randall H. Dean: On December 2, 2008, we amended and restated our employment agreement with Randall Dean. The agreement extends through January 15, 2011, provides for a base salary of $316,900 per year, subject to increases by the Committee, and allows Mr. Dean to be eligible for an annual performance bonus of up to 100 percent of his then-current annual base salary. Mr. Dean is also eligible to receive equity grants awarded to him under the LTIP in the Committe s discretion, and to participate in any benefit plans. Mr. Dean has agreed to keep certain information confidential as part of the agreement, and has also agreed to certain non-compete and non-solicitation provisions, should his employment be terminated. For additional information regarding provisions applicable upon a termination or a change of control, please see the narrative below entitled Potential Payments Upon a Termination or Change in Control.

Richard D. Moncrief: The Partnership entered into a resignation and release agreement with Mr. Moncrief effective as of December 12, 2008. In consideration for the releases and covenants contained in the agreement, Mr. Moncrief received a payment of $262,500 on January 21, 2009.

Restricted Units

The awards reported in the Stock Awards column of the Summary Compensation Table reflect awards of restricted units. Each restricted unit represents a contractual right to receive one common unit. The awards of restricted stock units granted to our Named Executive Officers during fiscal 2008 are generally subject to a four-year vesting schedule subject to such Named Executive Officer s continued employment with us through the vesting date. The Named Executive Officer does not have the right to sell or dispose of unvested restricted units, and unvested units are forfeited at the time the holder terminates employment. Restricted units participate in distributions on the same basis as other common units.

Options

No options were granted during fiscal 2008. Each option granted prior to fiscal 2008 and reported in the Option Awards column of the table above was granted with a per-share exercise price equal to the fair market value of a common unit on the grant date. For these purposes, and in accordance with the terms of the LTIP and our option grant practices, the fair market value is equal to the closing price of a common unit on the applicable grant date.

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.

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Salary and Cash Incentive Awards in Proportion to Total Compensation

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

Name	Percentage of Total Compensation
Byron R. Kelley	70%
James W. Hunt	
Stephen L. Arata	98%
Dan A. Fleckman	43%
Randall H. Dean	97%
Lawrence B. Connors	79%
Richard D. Moncrief	

Outstanding Equity Awards at December 31, 2008

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

	Stock Awards	
Name	Number of Shares or Units of Stock That Have Not Vested (#)(1)	Market Value of Shares or Units of Stock That Have Not Vested ($)(2)
Byron R. Kelley	106,300(1)	855,715
James W. Hunt		
Stephen L. Arata		
Dan A. Fleckman	75,000(3)	603,750
Randall H. Dean		
Lawrence B. Connors	7,500	60,375
Richard D. Moncrief(4)		

(1) The forfeiture restrictions on unvested restricted unit awards will lapse as follows: 23,150 on April 1, 2010; 23,150 on April 1, 2012; and the remaining 50,000 units on each of the four anniversaries of the April 1, 2008 grant date.

(2) Based on the closing price of $8.05 per common unit as of December 31, 2008.

(3) The forfeiture restrictions on unvested restricted unit awards will lapse as follows: 25 percent on each of the four anniversaries of the May 1st grant date.

The following table provides information relating to the exercise of unit option awards during 2008 on an aggregated basis for each of our Named Executive Officers. No forfeiture restrictions lapsed with respect to restricted unit awards during 2008.

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Option Exercises and Stock Vested for the Year Ended December 31, 2008

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting	Value Realized on Vesting ($)
Byron R. Kelley				
James W. Hunt	100,000	679,000		
Stephen L. Arata				
Dan A. Fleckman				
Randall H. Dean				
Lawrence B. Connors			2,500	61,700
Richard D. Moncrief				

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.

The employment agreement we maintain with Mr. Kelley provided for an initial grant of 106,300 restricted units to be governed by the terms of our LTIP, and these units will receive accelerated vesting upon a change in control as described below. In the event that 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 not receive the CEO Severance Payment before the first day of the seventh month following his termination from service, however, in the event that he is considered a specified employee pursuant to section 409A of the Code. He will also be required to sign a full release before receiving the CEO Severance Payment or the COBRA continuation coverage.

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.

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% of the combined voting power of our outstanding voting securities.

The Consulting Services Agreement we entered into on April 1, 2008 with Mr. Hunt served to terminate the employment agreement we previously maintained with Mr. Hunt, and thus terminated any potential severance or change in control payments contained within that agreement. Mr. Hunt remained subject to the confidentiality provisions and the non-compete and non-solicitation restrictions of that original employment agreement, however, until January 1, 2009.

The Resignation and Release Agreement we entered into on December 12, 2008 with Mr. Moncrief provided for a one-time payment of $262,500 (the Resignation Payment), as well as for six months of the monthly premium for continued medical coverage.

The employment agreement we maintain with Randall Dean provides for severance payments in the event that we terminate him without Cause or he terminates his employment for Good Reason. Mr. Dean would receive a payment equal to one year s salary, a pro-rated bonus payment calculated by assuming maximum targets were met for the year in which the termination occurs, continuation of medical coverage for thirty-six months, and all outstanding equity awards will become vested. Cash payments will be paid within seventy-four 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. Mr. Dean will be subject to a non-compete and non-solicitation period of three years following his termination of employment for any reason.

Good Reason termination events for Mr. Dean include: (i) a material change in Mr. Dean s duties, (ii) our failure to cure a material breach of the employment agreement, (iii) any changes in our key executive personnel or a material adverse change in their terms of employment, (iv) a material change in the business method by which we perform contract compression services, (v) the cessation of our quarterly bonus program, or (vi) a relocation of our corporate office. In the event that Mr. Dean terminates his employment as a result of items (iii) through (vi) above, however, he will not receive the portion of his severance that relates to a payment equaling one year s salary. Mr. Dean s 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) a court determination that Mr. Dean has breached his 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, (f) misappropriating our funds or property, or (g) acting in a manner that competes or materially injures us, or his material breach of his employment agreement.

The severance agreement we maintain with Mr. Fleckman provides for a severance payment if Mr. Fleckman is terminated without Cause, or if Mr. Fleckman terminates for Good Reason, before May 1, 2011. This severance payment will initially be in the amount of $900,000 reduced by the sum of: (i) the amount of salary he receives (or is due) up until the date of his termination of employment, and (ii) the bonus he either received the previous year, or if no such bonus was due, the bonus he should have received for the year in which the termination occurs (the Severance Payment). We will also pay for the company portion of the medical, dental and vision insurance that is comparable to the coverage we maintain for similarly situated employees for eighteen months (less the time, if any, by which his employment with us exceeded eighteen months on the date of termination). Mr. Fleckman will also be obligated to sign a release in our favor before receiving any severance

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payments. For purposes of Mr. Fleckman s severance agreement, the term Cause shall mean: (i) the misappropriation of funds or an act of fraud, (ii) the conviction of a felony, (iii) willful misconduct or gross negligence, (iv) a material violation of our code of conduct or workplace harassment policy, (v) habitual insobriety or substance abuse, or (vi) becoming subject to an order obtained or issued by the SEC for a securities law violation involving fraud. A Good Reason termination is defined as Mr. Fleckman s voluntary termination following our assignment of duties inconsistent with his position, a reduction in his base salary, or a termination or material reduction of a benefit under either our or any of our affiliates benefit plans.

Messrs. Arata and Connors do not have individual agreements that provide for severance or change in control payments.

The restricted units awarded under the LTIP to our NEOs contain provisions that provide for accelerated vesting upon either a Change in Control, or the death or Disability of the executive. 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 fifty percent or more of our voting power or voting securities, unless such person or group is Hicks, Muse, Tate & Furst Incorporated or an affiliate of such corporation, (2) the complete liquidation of either the Company, our General Partner, or us; (3) the sale of all or substantially all of the company s, our General Partner s, or our assets to anyone other than an entity that is wholly owned by one or more of the company, 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.

The following table quantifies the amounts that each 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, 2008. The precise amount that any NEO would receive cannot be determined with any certainty until an actual termination or change of control has occurred, but the following are our best estimates as to the amounts that the NEOs are entitled to as of December 31, 2008, and using our closing stock price on that date of $8.05. 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, 2008. For the NEOs that resigned or transitioned into a consulting agreement during the 2008 year, we have provided the amount that each NEO actually received pursuant to his termination of employment and transition.

Executive	Death or Disability	Change in Control	Without Cause or for Good Reason	Transition to Consulting Status
Byron R. Kelley				N/A
CEO Severance Payment[1]	N/A	N/A	$ 1,900,000	
Accelerated Equity[2]	$ 855,715	$ 855,715	N/A	
Continued Medical[3]	N/A	N/A	$ 10,524	
Supplemental Disability Benefits[4]	$ 280,000	$ 855,715	N/A	
Total	$ 1,135,715	$ 855,715	$ 1,910,524	
James W. Hunt[5]	N/A	N/A	N/A	$ 301,500
Richard D. Moncrief[6]	N/A	N/A	N/A	
Resignation Payment				$ 262,500
Continued Medical				$ 5,262
Total				$ 267,762
Randall H. Dean	N/A	N/A		N/A
Severance Payment[7]			$ 633,800	
Continued Medical[8]			$ 22,824	
Total			$ 656,624	
Dan A. Fleckman				N/A
Severance Payment[9]	N/A	N/A	$ 588,563	
Continued Medical[10]	N/A	N/A	$ 7,812	
Accelerated Equity[11]	$ 603,750	$ 603,750	N/A	
Total	$ 603,750	$ 603,750	$ 596,375	
Lawrence B. Connors[12]	$ 60,375	$ 60,375	N/A	N/A

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(1) This amount was calculated by multiplying Mr. Kelley s base salary 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 correct amount that Mr. Kelley would receive if the termination without Cause or for Good Reason occurred in connection with a Change in Control.
(2) This amount was calculated by multiplying the number of restricted units Mr. Kelley held on December 31, 2008 (106,300 units) by our closing stock price of $8.05.
(3) This amount was calculated by multiplying the monthly COBRA premium amount of $877 for twelve months.
(4) As of December 31, 2008, our long-term disability plan would cap monthly benefits at $15,000, leaving a remaining balance of $8,750. Mr. Kelley would receive this supplemental payment until he reaches the age of 65, and so the amount reflected here was calculated my multiplying $8,750 by thirty-two months.
(5) This amount was calculated by multiplying $33,500 by the nine months of consulting services that Mr. Hunt provided to us during the 2008 year.
(6) Mr. Moncrief received the Resignation Payment in consideration for the Resignation and Release Agreement that he entered into with us on December 12, 2008, though the amount was not actually paid to Mr. Moncrief until January of 2009. The amount of Mr. Moncrief s continued medical expenses were determined by using the monthly COBRA premium amount of $877 for six months.
(7) Mr. Dean s employment agreement provides for a potential annual bonus of 100 percent of his base salary, and using the assumption that 100 percent of the bonus target was achieved for the 2008 year, this amount is two times his base salary for 2008. This amount also assumes that upon a termination for Good Reason, such Good Reason event was not one of the articulated events in (iii) through (vi) above in Mr. Dean s Good Reason definition that would prevent him from receiving a portion of this payment, thus the amount Mr. Dean received upon a Good Reason termination could potentially be reduced by half.
(8) This amount was calculated by multiplying the monthly COBRA premium amount of $634 by thirty-six months.
(9) This amount was calculated by subtracting $150,000, the amount of salary we paid to Mr. Fleckman during the 2008 year, from $900,000. We then subtracted the amount of the bonus Mr. Fleckman would have been entitled to receive for the 2008 year assuming 100 percent of targets were achieved, or $161,437.
(10) This amount was calculated by multiplying the monthly COBRA premium amount of $434 by eighteen months.
(11) This amount was calculated by multiplying the number of restricted units Mr. Fleckman held on December 31, 2008 (75,000 units) by our closing stock price of $8.05.
(12) This amount was calculated by multiplying the number of restricted units Mr. Connors held on December 31, 2008 (7,500 units) by our closing stock price of $8.05.

Directors Compensation

The directors of the General Partner who are not employees of the General Partner or affiliated with the General Partner s controlling security holder received in 2008 an annual retainer of $30,000, a flat fee of $1,000 for each meeting of the board and $500 for each committee attended in person, a flat fee of $500 for each such meeting attended by telephone and fees at specified rates for consulting services. These amounts are determined on an annual basis by our board. In addition, those directors are eligible to participate in equity-based compensation plans of the General Partner. Determinations as to any such participation are made by the non-participating directors.

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Director Compensation for 2008

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, 2008.

Name	Fees Earned or Paid	Stock Awards(2)	Total ($)
Michael J. Bradley(1)	44,000	38,904	82,904
James F. Burgoyne(4)	39,500		39,500
Daniel R. Castagnola(4)	40,000		40,000
A. Dean Fuller(3)	32,000		32,000
Rodney L. Gray(1)	35,000	29,060	64,060
Paul J. Halas(4)	38,000		38,000
Mark T. Mellana(4)	41,000		41,000
John T. Mills(1)	52,125	38,904	91,029
Brian P. Ward(4)	36,500		36,500
J. Otis Winters(3)	30,375		30,375

(1) Messrs. Michael J. Bradley, Rodney L. Gary and John T. Mills were granted 5,000 units. The grant date fair value, are $155,300, $138,750 and $155,300 respectively.

(2) Each amount represents the earned portion of an award of 5,000 units awarded to each of the outside directors. The amounts included in the Stock Award column is the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2008 in accordance with the statement of Financial Accounting Standard No. 123(R).

(3) Messer. A. Dean Fuller and J. Otis Winters resigned from the board of directors on March 12, 2008 and January 24, 2008, respectively.

(4) Messer. 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 18, 2009, the beneficial ownership of our units by:

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

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

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Name of Beneficial Owner	Common Units	Percentage of Outstanding Common Units
Aircraft Services Corp[3]	24,679,557	30.4%
CDMR Holdings LLC[2]	7,276,506	9.0%
Kayne Anderson Capital Advisors, L.P.	6,601,879	8.1%
Neuberger Berman LLC	4,938,026	6.1%
Byron R. Kelley		*
James W. Hunt	639,732	0.8%
Stephen L. Arata[1]	207,973	0.3%
Dan A. Fleckman		*
Randall H. Dean	831,034	1.0%
Richard D. Moncrief	28,488	*
Lawrence B. Connors[1]	91,313	0.1%
Michael T. Bradley	1,250	*
James F. Burgoyne		*
Daniel R. Castagnola		*
Rodney Gray		*
Paul J. Halas		*
Mark T. Mellana		*
John T. Mills	6,250	*
Brian P. Ward		*
All directors and executive officers as a group (24 persons)	2,229,533	2.8%
Total number of units as of February 18, 2009	81,197,103	

(1) The common unit amount includes unit options which are currently exercisable in the following amount of common units: Mr. Arata - 35,000 and Mr. Connors - 15,000.

(2) CDMR Holdings, LLC is owned by four entities: two investment limited partnerships affiliated with Carlyle/Riverstone Global Energy and Power Fund II, L.P. (collectively the Carlyle/Riverstone Entities), and two entities owned primarily by certain members of management of our contract compression segment (the Management Entities). The Carlyle/Riverstone Entities and the Management Entities have a 67 percent and a 33 percent ownership interest in CDMR Holdings, LLC, respectively. The Carlyle/Riverstone Entities are C/R CDM Holdings II, L.P. and C/R CDM Investment Partnership III, L.P. The Carlyle/Riverstone Entities are associated with Riverstone Holdings LLC (Riverstone) and The Carlyle Group (Carlyle). The address of the Carlyle/Riverstone Entities and Riverstone is 712 Fifth Avenue, 51st Floor, New York, NY 10019. The address of Carlyle is 1001 Pennsylvania Avenue, N.W., Suite 200, Washington, D.C. 20004. The Carlyle/Riverstone Entities are ultimately controlled by a management committee. The Management Entities are CDM Investments, Ltd. and CDM Compression, LLC.

(3) Aircraft Services Corp is an affiliate of GECC.

* Ownership percentages are less than 0.1 percent.

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.

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Our General Partner s Board of Directors, or its compensation committee, in its discretion may terminate, suspend or discontinue the LTIP at any time with respect to any award that has not yet been granted. Our General Partner s Board of Directors, or its compensation committee, also has the right to alter or amend the LTIP or any part of the plan from time to time, including increasing the number of units that may be granted subject to unitholder approval as required by the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

The following table summarizes the number of securities remaining available for future issuance under the LTIP plan as of February 18, 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 holders[(1)]	381,618	25.94	270,384
Total	381,618	$ 25.94	270,384

(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 2,865,584 units. For more information, which did not require approval by our limited partners, refer to Item 11. Executive Compensation-Components of Compensation .

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

On February 26, 2009, the Partnership entered into a $45,000,000 unsecured revolving credit agreement with GECC, as administrative agent, the lenders party thereto and the guarantors party thereto. The commitments under the revolving credit facility will terminate automatically on the earlier to occur of the effectiveness of an amendment to the Partnership s fourth amended and restated credit agreement and April 30, 2009, and the Partnership will be required to prepay all outstanding loans upon the effectiveness of the amendment to the fourth amended and restated credit agreement. The maturity date under the revolving credit facility will be the earlier of the date that is three months after the final maturity date under the fourth amended and restated credit agreement and November 15, 2011.

Upon closing of the joint venture with GECC and the Alinda Investors, the Partnership will enter into an Area of Mutual Interest Agreement pursuant to which it will agree to offer the joint venture the first option to acquire or pursue certain natural gas transportation and storage opportunities identified by the Partnership in a defined area of northern Louisiana prior to the Partnership engaging in such opportunities outside of the joint venture.

Further information required for this item is provided in Item 1 Business Overview, Item 10 Directors, Executive Officers and Corporate Governance and Note 12, Related Party Transactions, include in the notes to the audited consolidated financial statements included in Item 8 Financial Statements and Supplementary Data.

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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 year ended December 31, 2008 and 2007. Deloitte & Touche LLP served as our independent registered public accountant until June 18, 2007.

Audit Fees. The following table sets forth fees billed by KPMG LLP and Deloitte & Touche LLP for the professional services rendered for the audits of our annual financial statements and other services rendered for the years ended December 31, 2008 and 2007:

	KPMG LLP December 31,		Deloitte & Touche LLP December 31, 2007
	2008	2007	
Audit fees(1)	1,732	2,062	335
Audit related fees(2)	31	50	53
Tax fees(3)	10		211
All other fees(4)			
Total	$ 1,773	$ 2,112	$ 599

(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.
(4) Consists of fees for services other than services reported above.

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

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

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

- the auditors internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;

the independence of the external auditors;

the aggregate fees billed by our external auditors for each of the previous two fiscal years; and

the rotation of the lead partner.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

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

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

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

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Signatures

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

REGENCY ENERGY PARTNERS LP

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

By: /s/ BYRON R. KELLEY
Byron R. Kelley
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, President, and Chief Executive Officer (Principal Executive Officer)	March 1, 2009
/s/ STEPHEN L. ARATA **Stephen L. Arata**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2009
/s/ LAWRENCE B. CONNORS **Lawrence B. Connors**	Senior Vice President, Finance and Accounting (Principal Accounting Officer)	March 1, 2009
/s/ JAMES F. BURGOYNE **James F. Burgoyne**	Director	March 1, 2009
/s/ DANIEL R. CASTAGNOLA **Daniel R. Castagnola**	Director	March 1, 2009
/s/ RODNEY L. GRAY **Rodney L. Gray**	Director	March 1, 2009
/s/ MARK T. MELLANA **Mark T. Mellana**	Director	March 1, 2009

/s/ JOHN T. MILLS	Director	March 1, 2009
John T. Mills		
/s/ BRIAN P. WARD	Director	March 1, 2009
Brian P. Ward		
/s/ MICHAEL J. BRADLEY	Director	March 1, 2009
Michael J. Bradley		
/s/ PAUL J. HALAS	Director	March 1, 2009
Paul J. Halas		

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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 Partnes LP and Regency NX, LLC	8-K	March 26, 2008
3.1	Certificate of Limited Partnership of Regency Energy Partners LP	S-1	333-128332
3.2	Form of Amended and Restated Limited Partnership Agreement of Regency Energy Partners LP (included as Appendix A to the Prospectus and including specimen unit certificate for the common units)	S-1	333-128332
3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	August 14, 2006
3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	September 21, 2006
3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	January 8, 2008
3.2.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	January 16, 2008
3.2.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	August 28, 2008
3.2.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	February 27, 2009
3.3	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	Certificate of Limited Partnership of Regency GP LP	S-1	333-128332
3.6	Form of Amended and Restated Limited Partnership Agreement of Regency GP LP	S-1	333-128332
4.1	Form of Common Unit Certificate	S-1	333-128332

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
4.2	Indenture for 8 3/8 percent Senior Notes due 2013, together with the global notes	10-K	March 30, 2007
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		
10.8	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		
10.10	Form of Indemnification Agreement between Regency GP LLC and Indemnities	S-1	333-128332
10.11	Form of Omnibus Agreement	S-1	333-128332
10.12	Amended and Restated Credit Agreement of Regency Gas Services LLC	S-1	333-128332
10.13	Amended and Restated Second Lien Credit Agreement of Regency Gas Services LLC	S-1	333-128332
10.14	Second Amended and Restated Credit Agreement of Regency Gas Services LLC	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	Form of Fourth Amended and Restated Credit Agreement of Regency Gas Services LP	8-K	August 14, 2006
10.17	Form of 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
10.18	Form of 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
10.19	Form of Amendment Agreement No. 5 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated February 14, 2008	8-K	February 19, 2008
10.20	Form of Amendment Agreement No. 6 with respect to the Fourth Amended and Restated Credit Agreement of Regency Gas Services LP dated May 9, 2008	8-K	October 16, 2008

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
10.21	Form of Master Lease Agreement of CDM Resource Management LLC		
10.22	Form of Revolving Credit Agreement dated as of February 26, 2009 of Regency Energy Partners LP		
12.1	Computation of Ratio of Earnings to Fixed Charges		
14.1	Code of Business Conduct	10-K	March 30, 2007
16.1	Letter from Deloitte & Touche LLP to the Securities and Exchange Commission dated June 18, 2007	8-K	June 19, 2007
21.1	List of Subsidiaries of Regency Energy Partners LP		
23.1	Consent of KPMG LLP		
23.2	Consent of Deloitte & Touche LLP		
24.1	Form by Power of Attorney		
31.1	Certifications pursuant to Rule 13a-14(a).		
31.2	Certifications pursuant to Rule 13a-14(a).		
32.1	Certifications pursuant to Section 1350.		
32.2	Certifications pursuant to Section 1350.		

Incorporated by reference to the signature page of this filing.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners

Regency Energy Partners LP:

We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners capital for the years then ended. 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, 2008 and 2007, and the results of their operations and their cash flows for the years then ended, 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, 2008, 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, 2009 expressed an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas

March 1, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners

Regency Energy Partners LP:

We have audited Regency Energy Partners LP s internal control over financial reporting as of December 31, 2008, 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Regency Energy Partners LP acquired CDM Resource Management, Ltd. (CDM) during 2008, and management excluded from its assessment of the effectiveness of Regency Energy Partners LP s internal control over financial reporting as of December 31, 2008, CDM s internal control over financial reporting associated with total assets of $881,552,000 and total revenues of $132,549,000 included in the consolidated financial statements of Regency Energy Partners LP and subsidiaries as of and for the year ended December 31, 2008. Our audit of internal control over financial reporting of Regency Energy Partners LP also excluded an evaluation of the internal control over financial reporting of CDM.

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 as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners capital for the years then ended, and our report dated March 1, 2009 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas

March 1, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Regency GP LLC and Unitholders of Regency Energy Partners LP:

We have audited the accompanying consolidated statements of operations, member interest and partners capital, comprehensive income (loss) and cash flows of Regency Energy Partners LP and subsidiaries (the Partnership) for the year ended December 31, 2006. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our 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 the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of the Partnership s operations and cash flows for the year ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Partnership accounted for its acquisition of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC as acquisitions of entities under common control in a manner similar to a pooling of interests.

/s/ Deloitte & Touche LLP

Dallas, Texas

March 29, 2007 (February 28, 2008 as to Note 4)

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Regency Energy Partners LP

Consolidated Balance Sheets

(in thousands except unit data)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 599	$ 32,971
Restricted cash	10,031	6,029
Trade accounts receivable, net of allowance of $941 in 2008 and $61 in 2007	40,875	16,487
Accrued revenues	96,712	117,622
Related party receivables	855	61
Assets from risk management activities	73,993	
Other current assets	13,338	6,723
Total current assets	236,403	179,893
Property, plant and equipment		
Gathering and transmission systems	652,267	635,206
Compression equipment	799,527	145,555
Gas plants and buildings	156,246	134,300
Other property, plant and equipment	167,256	105,399
Construction-in-progress	154,852	33,552
Total property, plant and equipment	1,930,148	1,054,012
Less accumulated depreciation	(226,594)	(140,903)
Property, plant and equipment, net	1,703,554	913,109
Other Assets:		
Intangible assets, net of accumulated amortization of $22,517 in 2008 and $8,929 in 2007	205,646	77,804
Long-term assets from risk management activities	36,798	
Goodwill	262,358	94,075
Other, net of accumulated amortization of debt issuance costs of $5,246 in 2008 and $2,488 in 2007	13,880	13,529
Total other assets	518,682	185,408
TOTAL ASSETS	$ 2,458,639	$ 1,278,410
LIABILITIES & PARTNERS CAPITAL		
Current Liabilities:		
Trade accounts payable	$ 65,483	$ 48,904
Accrued cost of gas and liquids	76,599	96,026
Related party payables		50
Escrow payable	10,031	6,029
Liabilities from risk management activities	42,691	37,852
Other current liabilities	22,146	9,397
Total current liabilities	216,950	198,258
Long-term liabilities from risk management activities	560	15,073
Other long-term liabilities	15,487	15,393
Long-term debt	1,126,229	481,500
Minority interest in consolidated subsidiary	13,161	4,893

Commitments and contingencies		
Partners Capital:		
Common units (55,519,903 and 41,283,079 units authorized; 54,796,701 and 40,514,895 units issued and outstanding at December 31, 2008 and 2007)	764,161	490,351
Class D common units (7,276,506 units authorized, issued and outstanding at December 31, 2008)	226,759	
Class E common units (4,701,034 units authorized, issued and outstanding at December 31, 2007)		92,962
Subordinated units (19,103,896 units authorized, issued and outstanding at December 31, 2008 and 2007)	(1,391)	7,019
General partner interest	29,283	11,286
Accumulated other comprehensive income (loss)	67,440	(38,325)
Total partners capital	1,086,252	563,293
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 2,458,639	$ 1,278,410

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Operations

(in thousands except unit data and per unit data)

	Year Ended December 31, 2008	2007	2006
REVENUES			
Gas sales	$ 1,126,760	$ 744,681	$ 560,620
NGL sales	409,476	347,737	256,672
Gathering, transportation and other fees, including related party amounts of $3,763, $1,350 and $2,160	286,507	100,644	63,071
Net realized and unrealized loss from risk management activities	(21,233)	(34,266)	(7,709)
Other	62,294	31,442	24,211
Total revenues	1,863,804	1,190,238	896,865
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $1,878, $14,165 and $1,630	1,408,333	976,145	740,446
Operation and maintenance	131,629	58,000	39,496
General and administrative	51,323	39,713	22,826
Loss on asset sales, net	472	1,522	
Management services termination fee	3,888		12,542
Transaction expenses	1,620	420	2,041
Depreciation and amortization	102,566	55,074	39,654
Total operating costs and expenses	1,699,831	1,130,874	857,005
OPERATING INCOME	163,973	59,364	39,860
Interest expense, net	(63,243)	(52,016)	(37,182)
Loss on debt refinancing		(21,200)	(10,761)
Other income and deductions, net	332	1,252	839
INCOME (LOSS) BEFORE INCOME TAXES AND MINORITY INTEREST	101,062	(12,600)	(7,244)
Income tax expense (benefit)	(266)	931	
Minority interest	312	305	
NET INCOME (LOSS)	$ 101,016	$ (13,836)	$ (7,244)
Less: Net income from January 1-31, 2006			1,564
Net income (loss) for partners	$ 101,016	$ (13,836)	$ (8,808)
General partner s interest in current period net income (loss), including IDR	9,967	(393)	(176)
Beneficial conversion feature for Class C common units		1,385	3,587
Beneficial conversion feature for Class D common units	7,199		
Limited partners interest in net income (loss)	$ 83,850	$ (14,828)	$ (12,219)
Basic and Diluted earnings per unit:			
Amount allocated to common and subordinated units	$ 83,850	$ (20,620)	$ (11,333)
Weighted average number of common and subordinated units outstanding	66,042,830	51,056,769	38,207,792
Basic income (loss) per common and subordinated unit	$ 1.27	$ (0.40)	$ (0.30)
Diluted income (loss) per common and subordinated unit	$ 1.24	$ (0.40)	$ (0.30)
Distributions per unit	$ 1.71	$ 1.52	$ 0.9417

Amount allocated to Class B common units	$	$	$ (886)
Weighted average number of Class B common units outstanding		651,964	5,173,189
Income per Class B common unit	$	$	$ (0.17)
Distributions per unit	$	$	$
Amount allocated to Class C common units	$	$ 1,385	$ 3,587
Total number of Class C common units outstanding		2,857,143	2,857,143
Income per Class C common unit due to beneficial conversion feature	$	$ 0.48	$ 1.26
Distributions per unit	$	$	$
Amount allocated to Class D common units	$ 7,199	$	$
Total number of Class D common units outstanding	7,276,506		
Income per Class D common unit due to beneficial conversion feature	$ 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	$

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Comprehensive Income (Loss)

(in thousands)

	Year Ended December 31,		
	2008	2007	2006
Net income (loss)	$ 101,016	$ (13,836)	$ (7,244)
Net hedging amounts reclassified to earnings	35,512	19,362	1,815
Net change in fair value of cash flow hedges	70,253	(58,706)	10,166
Comprehensive income (loss)	$ 206,781	$ (53,180)	$ 4,737

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Cash Flows

(in thousands)

	Year Ended December 31, 2008	2007	2006
OPERATING ACTIVITIES			
Net income (loss)	$ 101,016	$ (13,836)	$ (7,244)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization	105,324	57,069	39,287
Write-off of debt issuance costs		5,078	10,761
Equity income and minority interest in earnings	312	262	(532)
Risk management portfolio valuation changes	(14,700)	14,667	(2,262)
Loss on asset sales	472	1,522	
Unit based compensation expenses	4,306	15,534	2,906
Gain on insurance settlements	(3,282)		
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and accrued revenues, and related party receivables	18,648	(28,789)	(5,506)
Other current assets	(6,615)	(1,394)	104
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(40,772)	30,089	(1,359)
Other current liabilities	12,749	(149)	3,640
Proceeds from early termination of interest rate swap			4,940
Amount of swap termination proceeds reclassified into earnings		(1,078)	(3,862)
Other assets and liabilities	3,840	554	3,283
Net cash flows provided by operating activities	181,298	79,529	44,156
INVESTING ACTIVITIES			
Capital expenditures	(375,083)	(129,784)	(142,423)
Acquisitions	(577,668)	(34,855)	(81,695)
Acquisition of investment in unconsolidated subsidiary, net of $100 cash		(5,000)	
Proceeds from asset sales	840	11,706	
Proceeds from insurance settlements	3,282		
Other			468
Net cash flows used in investing activities	(948,629)	(157,933)	(223,650)
FINANCING ACTIVITIES			
Net borrowings under revolving credit facilities	644,729	59,300	14,700
Borrowings under credit facilities			599,650
Repayments under credit facilities		(50,000)	(858,600)
Proceeds (repayments) of senior notes, net of debt issuance costs		(192,500)	536,175
Partner contributions	11,746	7,735	3,786
Partner distributions	(120,591)	(79,933)	(37,144)
Proceeds from option exercises	2,700		
Debt issuance costs	(2,940)	(2,427)	(10,488)
Proceeds from equity issuances, net of issuance costs	199,315	353,546	312,700
FrontStreet distributions		(9,695)	
FrontStreet contributions		13,417	
Acquisition of assets between entities under common control			(62,074)
Borrowings under TexStar loan agreement			85,000
Repayments under TexStar loan agreement			(155,000)
Cash distribution to HM Capital			(243,758)
Proceeds from exercise of over allotment option			26,163
Over allotment option proceeds to HM Capital			(26,163)

Net cash flows provided by financing activities	734,959	99,443	184,947
Net increase (decrease) in cash and cash equivalents	(32,372)	21,039	5,453
Cash and cash equivalents at beginning of period	32,971	9,139	3,686
Cash acquired from FrontStreet		2,793	
Cash and cash equivalents at end of period	$ 599	$ 32,971	$ 9,139
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 59,969	$ 67,844	$ 33,347
Income taxes paid	605		
Non-cash capital expenditures in accounts payable	25,845	7,761	23,822
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	

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Member Interest and Partners Capital

(in thousands except unit data)

	Units						Member	Common
	Common	**Class B**	**Class C**	**Class D**	**Class E**	**Subordinated**	**Interest**	**Unitholders**
Balance December 31, 2005							$ 241,924	$
Net income through January 31, 2006							1,564	
Net hedging loss reclassified to earnings								
Net change in fair value of cash flow hedges								
Balance January 31, 2006							243,488	
Contribution of net investment to unitholders	5,353,896					19,103,896	(182,320)	89,337
Proceeds from IPO, net of issuance costs	13,750,000							125,907
Net proceeds from exercise of over allotment option	1,400,000							26,163
Over allotment option net proceeds to HM Capital Investors	(1,400,000)							(26,163)
Capital reimbursement to HM Capital Partners								(119,441)
Offering costs								(2,056)
Issuance of Class B Common Units for TexStar member interest		5,173,189					(61,168)	
Payment to HM Capital for TexStar net of repayment of promissory note								(30,418)
Other								(64)
Issuance of Class C Common Units net of costs			2,857,143					
Issuance of restricted common units	516,500							
Unit based compensation expenses								1,339
General partner contributions								
Partner distributions								(18,409)
Net loss from February 1 through December 31, 2006								(4,003)
Net hedging loss reclassified to earnings								
Net change in fair value of cash flow hedges								
Balance December 31, 2006	19,620,396	5,173,189	2,857,143			19,103,896		42,192
Conversion of Class B and C to common units	8,030,332	(5,173,189)	(2,857,143)					120,663
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
General partner contributions								
Partner distributions								(49,296)
Acquisition of FrontStreet					4,701,034			
FrontStreet contributions								
FrontStreet distributions								
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				
	559,863							2,700

Issuance of restricted common units and option exercises, net of forfeitures						
Issuance of common units	9,020,909					199,315
Working capital adjustment on FrontStreet						
Conversion of Class E common units	4,701,034		(4,701,034)			92,104
Unit based compensation expenses						4,306
General partner contributions						
Partner distributions						(84,207)
Net income						59,592
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

See accompanying notes to the consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Member Interest and Partners Capital (Continued)

(in thousands except unit data)

	Class B Unitholders	Class C Unitholders	Class D Unitholders	Class E Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Total
Balance December 31, 2005	$	$	$	$	$	$	$ (10,962)	$ 230,962
Net income through January 31, 2006								1,564
Net hedging loss reclassified to earnings							616	616
Net change in fair value of cash flow hedges							2,581	2,581
Balance January 31, 2006							(7,765)	235,723
Contribution of net investment to unitholders					89,337	3,646		
Proceeds from IPO, net of issuance costs					125,907	5,139		256,953
Net proceeds from exercise of over allotment option								26,163
Over allotment option net proceeds to HM Capital Investors								(26,163)
Capital reimbursement to HM Capital Partners					(119,441)	(4,876)		(243,758)
Offering costs					(2,056)	(83)		(4,195)
Issuance of Class B Common Units for TexStar member interest	61,168							
Payment to HM Capital for TexStar net of repayment of promissory note					(29,744)	(1,214)		(61,376)
Other	(17)	(9)			(63)	(2)		(155)
Issuance of Class C Common Units net of costs		59,942						59,942
Issuance of restricted common units								
Unit based compensation expenses	146	59			1,304	58		2,906
General partner contributions						3,786		3,786
Partner distributions					(18,001)	(735)		(37,145)
Net loss from February 1 through December 31, 2006	(626)				(4,003)	(176)		(8,808)
Net hedging loss reclassified to earnings							7,585	7,585
Net change in fair value of cash flow hedges							1,199	1,199
Balance December 31, 2006	60,671	59,992			43,240	5,543	1,019	212,657
Conversion of Class B and C to common units	(60,671)	(59,992)						
Issuance of common units for acquisition								19,724
Issuance of common units								353,446
Issuance of restricted common units								
Exercise of common unit options								100
Unit based compensation expenses								15,534
General partner contributions						7,735		7,735
Partner distributions					(29,038)	(1,599)		(79,933)
Acquisition of FrontStreet				83,448				83,448
FrontStreet contributions				13,417				13,417
FrontStreet distributions				(9,695)				(9,695)
Net income (loss)				5,792	(7,198)	(393)		(13,836)
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)	563,293
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)
Conversion of Class E common units				(92,104)				
Unit based compensation expenses								4,306
General partner contributions						11,746		11,746
Partner distributions					(32,668)	(3,716)		(120,591)
Net income			7,199		24,258	9,967		101,016
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	$ 1,086,252

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Notes to Consolidated Financial Statements

For the Year Ended December 31, 2008

1. Organization and Basis of Presentation

Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP (Partnership), a Delaware limited partnership, and its predecessor, Regency Gas Services LLC (Predecessor). The Partnership was formed on September 8, 2005; on February 3, 2006, in conjunction with its IPO, the Predecessor was converted to a limited partnership, Regency Gas Services LP (RGS), and became a wholly owned subsidiary of the Partnership. The Partnership and its subsidiaries are engaged in the business of gathering, treating, processing, transporting, and marketing 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 August 15, 2006, the Partnership acquired all the outstanding equity of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC (collectively TexStar), from HMTF Gas Partners II, L.P. (HMTF Gas Partners), an affiliate of HM Capital Partners LLC (HM Capital Partners) (TexStar Acquisition). Because the TexStar Acquisition was a transaction between commonly controlled entities, the Partnership accounted for the TexStar Acquisition in a manner similar to a pooling of interests. Information included in these financial statements is presented as if the Partnership and TexStar had been combined throughout the periods presented in which common control existed, December 1, 2004 forward. See Note 5.

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).

On January 7, 2008, the Partnership acquired all of the outstanding equity and minority interest (the FrontStreet Acquisition) of FrontStreet from ASC and EnergyOne. FrontStreet owns 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.

In connection with the FrontStreet Acquisition, the Partnership amended the Partnership Agreement to create the Class E common units. 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 of operating surplus 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 afforded by Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

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.

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The following table summarizes the book values of the assets acquired and 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

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 necessarily include the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management s available knowledge of current and expected future events, actual results could be different from those estimates.

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

Restricted Cash. Restricted cash of $10,031,000 is held in escrow for purchase indemnifications related to the Nexus 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.

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. Gas 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, 2008, 2007, and 2006, the Partnership capitalized interest of $2,409,000, $1,754,000, and $511,000, 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 assesses long-lived 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 2008, 2007 or 2006.

The Partnership accounts for its asset retirement obligations in accordance with SFAS No. 143 Accounting for Asset Retirement Obligations and FIN 47 Accounting for Conditional Asset Retirement Obligations. These accounting standards require the Partnership to recognize 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

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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 $88,828,000, $50,719,000, and $36,880,000 for the years ended December 31, 2008, 2007, and 2006, 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 thirty years.

The Partnership evaluates the carrying value of intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability, the Partnership compares the carrying value to the undiscounted future cash flows the intangible assets are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangible assets, the intangibles are written down to their fair value. The Partnership did not record any impairment in 2008, 2007, or 2006.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of 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, 2008, 2007, or 2006.

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 as allowed under EITF 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement.

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, 2008 and 2007 were immaterial.

Revenue Recognition. The Partnership earns revenues from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, and (iii) contract compression services. Revenues 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. Revenues 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 revenues gross in the consolidated statements of operations, in accordance with EITF Issue No. 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent. Except for fee-based agreements, the Partnership acts as the principal in these transactions, takes title to the product, and incurs the risks and rewards of ownership. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Risk Management Activities. 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. The Partnership accounts for derivative financial instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended (SFAS 133), whereby all derivative financial instruments are recorded in 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 against 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 loss from risk management activities 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 or 5 years. The amount of matching contributions for the years ended December 31, 2008, 2007, and 2006 was $395,000, $469,000 and $201,000, respectively, and is 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. Effective January 1, 2007, the Partnership became 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 $8,156,000 and $8,642,000 as of December 31, 2008 and 2007 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 adopted the provisions of FIN No. 48 Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement 109 , on January 1, 2007. Upon adoption, the Partnership did not identify or record any uncertain tax positions not meeting the more likely than not standard. The Partnership s entities that are required to pay federal income tax recognized current income tax expense of $ 62,000 and deferred income tax benefit of $486,000 using a 35 percent effective rate.

Equity-Based Compensation. The Partnership adopted SFAS No. 123(R) Share-Based Payment in the first quarter of 2006 upon the creation of LTIP. The adoption had no impact on the consolidated financial position, results of operations or cash flows as no LTIP awards were granted prior to adoption.

Earnings per unit. Basic net income per limited partner unit is computed in accordance with SFAS No. 128, Earnings Per Share, as interpreted by EITF Issue No. 03-6 (EITF 03-6), Participating Securities and the Two-Class method under FASB Statement No. 128. 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. 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. In periods when the Partnership s aggregate net income exceeds the aggregate distributions, EITF 03-6 requires the Partnership to present earnings per unit as if all of the earnings for the periods were distributed. Diluted net income per limited partner 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 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.

Recently Issued Accounting Standards. In December 2007, the FASB issued SFAS No. 141(R), Business Combinations (SFAS 141(R)), which significantly changes the accounting for business acquisitions both during the period of the acquisition and in subsequent periods. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008. Generally, the effects of SFAS No. 141(R) will depend on future acquisitions.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (SFAS 160), which will significantly change the accounting and reporting related to noncontrolling interests in a consolidated subsidiary. SFAS 160 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2008. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows as a result of the adoption of this standard.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 (SFAS 161). SFAS 161 requires enhanced disclosures about derivative and hedging activities. These enhanced disclosures will address (a) how and why a company uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations and (c) how derivative instruments and related hedged items affect a company s financial position, results of operations and cash flows. SFAS 161 is effective for fiscal years and interim periods beginning on or after November 15, 2008, with earlier adoption allowed. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

In March 2008, the FASB issued EITF 07-4, Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships (EITF 07-4). EITF 07-4 defines how to allocate net income among the

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various classes of equity, including incentive distribution rights, narrowing the number of currently acceptable methods. The standard becomes effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted, and EITF No. 07-4 must be applied retrospectively for all financial statements presented. This new standard is not expected to have a material impact on the Partnership s financial position, results of operations or cash flows.

In April 2008, FASB issued FSP No. 142-3, Determination of the Useful Life of Intangible Assets (FSP 142-3), which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of intangible assets. The objective of FSP 142-3 is to better match the useful life of intangible assets to the cash flow generated. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Early adoption of this statement is not permitted. The Partnership is currently evaluating the potential impact of this standard on its financial position, results of operations and cash flows.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity of GAAP. SFAS 162 s effective date is November 15, 2008. The adoption of SFAS 162 is not expected to have a material impact on the Partnership s financial position, results of operations or cash flows.

In June 2008, the FASB issued FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). Based on this guidance, the Partnership will include non-vested units granted under its LTIP in the basic earnings per unit calculation. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period earnings per unit data will be adjusted. Early application is not permitted. This new standard is not expected to have a material impact on the Partnership s financial position, results of operations or cash flows.

3. Partners Capital and Distributions

Initial Public Offering. On February 3, 2006, the Partnership offered and sold 13,750,000 common units, representing a 35.3 percent limited partner interest in the Partnership, in its IPO, at a price of $20.00 per unit. Total proceeds from the sale of the units were $275,000,000, before offering costs and underwriting commissions. On March 8, 2006, the Partnership sold an additional 1,400,000 common units at a price of $20.00 per unit as the underwriters exercised a portion of their over allotment option.

Class B Common Units. On August 15, 2006, the Partnership issued 5,173,189 of Class B common units to HMTF Gas Partners as partial consideration for the TexStar Acquisition. The Class B common units had the same terms and conditions as the Partnership s common units, except that the Class B common units were not entitled to participate in earnings or distributions by the Partnership. The Class B common units were converted into common units without the payment of further consideration on a one-for-one basis on February 15, 2007.

Class C Common Units. On September 21, 2006, the Partnership entered into a Class C Unit Purchase Agreement with certain purchasers, pursuant to which the purchasers purchased 2,857,143 Class C common units representing limited partner interests in the Partnership at a price of $21.00 per unit. The Class C common units had the same terms and conditions as the Partnership s common units, except that the Class C common units were not entitled to participate in earnings or distributions by the Partnership. The Class C common units were converted into common units without the payment of further consideration on a one-for-one basis on February 8, 2007.

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 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 Resource Management Ltd. 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 under Section 4(2) thereof. The Class D common units were converted into common units without the payment of further consideration on a one-for-one basis on February 9, 2009.

Common Unit Offerings. On July 26, 2007, the Partnership sold 10,000,000 common units for and received $307,680,000 in proceeds, excluding the General Partner s proportionate capital contribution of $6,279,000 and offering expenses of $386,000. On July 31, 2007, the Partnership sold an additional 1,500,000 and received $46,152,000 from this sale after deducting underwriting discounts and commissions and excluding the general partner s proportionate capital contribution of $942,000. On August 1, 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.

Distributions. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of the Partnership s Available Cash (defined below) 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 1,656,676 equivalent units as of December 31, 2008. 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. Please read the *Distributions of Available Cash during the Subordination Period* and *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner s incentive distribution rights.

Subordinated Units. All of the subordinated units are held by GE EFS and members of senior management. The partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the Minimum Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution

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on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is the first day of any quarter beginning after December 31, 2008. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders. The subordinated units converted into common units on a one-for-one basis on February 17, 2009.

Distributions of Available Cash During the Subordination Period. The partnership agreement requires that we make distributions of Available Cash for any quarter during the subordination period in the following manner:

first*,* 98 percent to the common unitholders, pro rata, and 2 percent to the general partner, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;

second, 98 percent to the common unitholders, pro rata, and 2 percent to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;

third, 98 percent to the subordinated unitholders, pro rata, and 2 percent to the general partner, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;

fourth, 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;

fifth, 85 percent to all unitholders, pro rata, and 15 percent to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;

sixth, 75 percent to all unitholders, pro rata, and 25 percent to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 50 percent to all unitholders, pro rata, and 50 percent to the general partner.

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

first, 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;

second, 85 percent to all unitholders, pro rata, and 15 percent to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;

third, 75 percent to all unitholders, pro rata, and 25 percent to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 50 percent to all unitholders, pro rata, and 50 percent to the general partner.

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Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2008 and 2007:

Distribution Date	Cash Distribution (per Unit)
November 14, 2008	$ 0.4450
August 14, 2008	0.4450
May 14, 2008	0.4200
February 14, 2008	0.4000
November 14, 2007	0.3900
August 14, 2007	0.3800
May 15, 2007	0.3800
February 14, 2007	0.3700
November 14, 2006	0.3700
August 14, 2006	0.3500
May 15, 2006	0.2217

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 year ended December 31, 2008.

	For the Year Ended December 31, 2008		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)		
Basic Earnings per Unit			
Limited partner s interest in net income	$ 83,850	66,042,830	$ 1.27
Effect of Dilutive Securities			
Common unit options		30,580	
Restricted common units		5,468	
Class D common units	7,199	7,276,506	
Diluted Earnings per Unit	$ 91,049	73,355,384	$ 1.24

Diluted earnings per unit equals basic because all instruments were antidilutive for the years ended December 31, 2007 and 2006.

Loss per unit for the year ended December 31, 2006 reflects only the eleven months since the closing of the Partnership s IPO on February 3, 2006. Accordingly, results for January 2006 have been excluded from the calculation of loss per unit. While the non-vested (or restricted) units are deemed to be outstanding for legal purposes, they have been excluded from the calculation of basic loss per unit in accordance with SFAS 128.

In connection with the TexStar acquisition, the Partnership issued 5,173,189 of Class B common units to HMTF Gas Partners, an affiliate of HM Capital, which at the time owned a controlling interest in the Partnership. 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 B common units represents amounts earned by TexStar between the date of common control and the transaction date.

On September 21, 2006, the Partnership issued 2,857,143 Class C common units. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class C common units are outstanding, as indicated on the statements of operations in the line item entitled beneficial conversion feature for Class C common units.

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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 are outstanding, as indicated on the statements of operations in the line item entitled beneficial conversion feature for Class D common units.

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

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

	December 31, 2007	December 31, 2006
Restricted common units	397,500	516,500
Common unit options	738,668	909,600

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.

As previously disclosed in the December 31, 2007 Form 10-K, the Partnership identified and corrected an error in the calculation of earnings per unit resulting from the issuance of Class C common units at a discount. At the commitment date to sell the Class C common units the purchase price of $21.00 per unit represented a $1.74 discount from the fair value of the Partnership s common units. Under EITF No. 98-5, Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios, the discount represented a beneficial conversion feature (BCF) that should have been treated as a non-cash distribution for purposes of calculating earnings per unit. The BCF is reflected in loss per unit using the effective yield method over the period the Class C common units are outstanding, as indicated on the statements of operations in the line item entitled beneficial conversion feature for Class C common units . The error is immaterial and had no impact on the Partnership s net loss or partners capital.

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The following table depicts the effect on earnings per unit for the year ended December 31, 2006.

	As Previously Reported in the December 31, 2006 Form 10-K		As Restated in the December 31, 2007 Form 10-K*	
NET LOSS	$	(7,244)	$	(7,244)
Less: Net income from January 1-31, 2006		1,564		1,564
Net loss for partners		(8,808)		(8,808)
General partner s interest		(176)		(176)
Beneficial conversion feature for Class C common units				3,587
Limited partners interest	$	(8,632)	$	(12,219)
Basic and diluted earnings per unit:				
Amount allocated to common and subordinated units	$	(8,006)	$	(11,333)
Weighted average number of common and subordinated units outstanding		38,207,792		38,207,792
Loss per common and subordinated unit	$	(0.21)	$	(0.30)
Distributions declared per unit	$		$	0.94
Amount allocated to Class B common units	$	(626)	$	(886)
Weighted average number of Class B common units outstanding		5,173,189		5,173,189
Loss per Class B common unit	$	(0.12)	$	(0.17)
Distributions declared per unit	$		$	
Amount allocated to Class C common units	$		$	3,587
Total Class C common units outstanding		871,817		2,857,143
Income per Class C common unit due to beneficial conversion feature	$		$	1.26
Distributions declared per unit	$		$	

* Amounts included in the consolidated statement of operations for the year ended December 31, 2007 have been recast for as-if pooling accounting treatment for the FrontStreet Acquisition.

5. Acquisitions and Dispositions

2008

FrontStreet. On January 7, 2008, the Partnership acquired all of the outstanding equity and minority interest of FrontStreet from ASC and EnergyOne, which is further described in Note 1, Organization and Basis of Presentation.

CDM Resource Management, Ltd. On January 15, 2008, the Partnership and an indirect wholly owned subsidiary of the Partnership (Merger Sub) consummated an agreement and plan of merger (the Merger Agreement) with CDM Resource Management, Ltd. CDM provides its customers with turn-key natural gas contract compression services to maximize their natural gas and crude oil production, throughput, and cash flow in Texas, Louisiana, and Arkansas. The Partnership operates and manages CDM as a separate reportable segment.

The total purchase price paid by the Partnership for the partnership interests of CDM consisted of (a) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, 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. Of the Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing with respect to any obligations under the Merger Agreement, including obligations for breaches of representation, warranties and covenants.

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

	At January 15, 2008 (in thousands)
Current assets	$ 19,463
Other assets	4,658
Gas plants and buildings	1,528
Gathering and transmission systems	420,974
Other property, plant and equipment	2,728
Construction-in-progress	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. On March 25, 2008, the Partnership acquired Nexus (Nexus Acquisition) by merger for $88,486,000 in cash, including customary closing adjustments and direct transaction costs. Nexus Gas Partners LLC, the sole member of Nexus prior to the merger (Nexus Member), deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment. The Partnership funded the Nexus Acquisition through borrowings under its existing revolving 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

Upon consummation of the Nexus Acquisition, the Partnership acquired Nexus rights under a Purchase and Sale Agreement (the Sonat Agreement) between Nexus and Sonat. Pursuant to the Sonat Agreement, Nexus will purchase 136 miles of pipeline from Sonat (the Sonat Asset Acquisition) that could facilitate the Nexus gathering system s integration into the Partnership s north Louisiana asset base. The Sonat Asset Acquisition is subject to abandonment approval and jurisdictional redetermination by the FERC, as well as customary closing conditions. Upon closing of the Sonat Asset Acquisition, the Partnership will pay Sonat $27,500,000, and, if the closing occurs on or prior to March 1, 2010, on certain terms and conditions as provided in the Merger Agreement, the Partnership will make an additional payment of $25,000,000 to the Nexus Member.

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 Midcontinent 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 twenty 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. On April 2, 2007, the Partnership and its indirect wholly-owned subsidiary, Pueblo Holdings, acquired all the outstanding equity of Pueblo. Pueblo owned and operated natural gas gathering, treating and processing assets located in south Texas. These assets are comprised of 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 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 revolving credit facility.

The Pueblo Acquisition offers the opportunity to reroute gas to one of the Partnership s existing gas processing plants which is expected 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
Total assets acquired	$ 65,313
Current liabilities	(1,187)
Long-term liabilities	(9,492)
Total purchase price	$ 54,634

2006

TexStar. On August 15, 2006, the Partnership acquired all the outstanding equity of TexStar by issuing 5,173,189 Class B common units valued at $119,183,000, a cash payment of $62,074,000 and the assumption of $167,652,000 of TexStar s outstanding bank debt. Because the TexStar Acquisition is a transaction between commonly controlled entities, the Partnership accounted for the TexStar Acquisition in a manner similar to a

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pooling of interests. As a result, the historical financial statements of the Partnership and TexStar have been combined to reflect the historical operations, financial position and cash flows from the date common control began (December 1, 2004) forward.

The following table presents the revenues and net income for the previously separate entities and the combined amounts presented in these audited consolidated financial statements.

	Year Ended December 31, 2006 (in thousands)
Revenue	
Regency Energy Partners	$ 812,564
TexStar Field Services	84,301
Combined	$ 896,865
Net Loss	
Regency Energy Partners	$ (1,639)
TexStar Field Services	(5,605)
Combined	$ (7,244)

Como. On July 25, 2006, TexStar acquired certain natural gas gathering, treating and processing assets from the other parties for $81,695,000 including transaction costs. The assets acquired consisted of approximately 59 miles of pipelines and certain specified contracts (the Como Assets). The results of operations of the Como Assets have been included in the statements of operations beginning July 26, 2006. The Partnership s purchase price allocation resulted in $18,493,000 being allocated to property, plant and equipment and $63,202,000 being allocated to intangible assets.

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The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM, Nexus, Pueblo and Como had occurred as of the beginning of the periods 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, 2008	2007	2006
	(in thousands except unit and per unit data)		
Revenue	$ 1,871,011	$ 1,317,365	$ 952,229
Net income (loss)	102,830	(6,913)	(6,876)
Less net income from January 1 31, 2006			1,564
Net income (loss) for partners	102,830	(6,913)	(8,440)
Less:			
General partner s interest in current period net income (loss), including IDR	9,833	(255)	(169)
Beneficial conversion feature for Class C common units		1,385	3,587
Beneficial conversion feature for Class D common units	7,199		
Limited partners interest in net income (loss)	$ 85,798	$ (8,043)	$ (11,858)
Basic and Diluted earnings per unit:			
Amount allocated to common and subordinated units	$ 85,798	$ (13,835)	$ (10,999)
Weighted average number of common and subordinated units outstanding	66,042,830	51,056,769	38,207,792
Basic income (loss) per common and subordinated unit	$ 1.30	$ (0.27)	$ (0.29)
Diluted income (loss) per common and subordinated unit	$ 1.27	$ (0.27)	$ (0.29)
Distributions per unit	$ 1.71	$ 1.52	$ 0.9417
Amount allocated to Class B common units	$	$	$ (859)
Weighted average number of Class B common units outstanding		651,964	5,173,189
Income per Class B common unit	$	$	$ (0.17)
Distributions per unit	$	$	$
Amount allocated to Class C common units	$	$ 1,385	$ 3,587
Total number of Class C common units outstanding		2,857,143	2,857,143
Income per Class C common unit due to beneficial conversion feature	$	$ 0.48	$ 1.26
Distributions per unit	$	$	$
Amount allocated to Class D common units	$ 7,199	$	$
Total number of Class D common units outstanding	7,276,506		
Income per Class D common unit due to beneficial conversion feature	$ 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	$

6. Risk Management Activities

The net fair value of the Partnership s risk management activities constituted a net asset of $67,540,000 at December 31, 2008 and a net liability of $52,925,000 at December 31, 2007. The Partnership expects to

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reclassify $53,047,000 of net hedging gains to revenues or interest expense from accumulated other comprehensive income (loss) in the next twelve months. The Partnership recorded $15,655,000 of net mark-to-market gains for the year ended December 31, 2008 and $14,559,000 of mark-to-market losses for the year ended December 31, 2007 for certain hedges that, did not initially, or do not qualify for hedge accounting. The Partnership also recognized $545,000 of ineffectiveness gain for the year ended December 31, 2008 and $486,000 of ineffectiveness loss for the year ended December 31, 2007.

In the year ended December 31, 2008, the Partnership recorded in net realized and unrealized loss from risk management activities $1,500,000 of losses associated with its credit risk assessment in accordance with SFAS No. 157, Fair Value Measurements (SFAS 157).

The Partnership s hedging positions help reduce exposure to variability of future commodity prices through 2010 and future interest rates on $300,000,000 of long-term debt under its revolving credit facility through March 5, 2010, the date the interest rate swaps expire.

Effective June 19, 2007, the Partnership elected to account for all outstanding commodity hedging instruments on a mark-to-market basis except for the portion pursuant to which all NGL products for a particular year were hedged and the hedging relationship was, for accounting purposes, effective. At December 31, 2008, the Partnership has the following commodity hedging programs that qualify for hedge accounting: the 2009 NGL, natural gas and West Texas Intermediate crude oil hedging programs and the 2010 West Texas Intermediate crude oil hedging program.

In March 2008, the Partnership entered offsetting trades against its existing 2009 NGL portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its 2009 NGL hedges. This group of trades, along with the pre-existing 2009 NGL portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated under SFAS 133 as cash flow hedges. In May 2008, the Partnership entered into commodity swaps to hedge a portion of its 2010 NGL commodity risk, except for ethane, which are accounted for using mark-to-market accounting.

The Partnership accounts for a portion of its 2008 and, prior to August 2008, accounted for all of its 2009 West Texas Intermediate crude oil swaps using mark-to-market accounting. In August 2008, the Partnership entered into an offsetting trade against its existing 2009 West Texas Intermediate crude oil swap to minimize the volatility of the original 2009 swap. Simultaneously, the Partnership executed an additional 2009 West Texas Intermediate crude oil swap, which was designated under SFAS No. 133 as a cash flow hedge. In May 2008, the Partnership entered into a West Texas Intermediate crude oil swap to hedge its 2010 condensate price risk, which was designated as a cash flow hedge in June 2008.

On December 2, 2008, the Partnership entered into two natural gas swaps to hedge its equity exposure to natural gas for calendar year 2009. These natural gas swaps were designated as cash flow hedges under SFAS 133 on December 2, 2008.

On February 29, 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (1.5 percent as of December 31, 2008) through March 5, 2010. These interest rate swaps were designated as cash flow hedges in March 2008.

Upon the early termination of an interest rate swap with a notional debt amount of $200,000,000 that was effective from April 2007 through March 2009, the Partnership received $3,550,000 in cash from the counterparty. The Partnership reclassified $1,078,000 and $2,663,000 from accumulated other comprehensive income (loss), reducing interest expense, net in the year ended December 31, 2007 and 2006, respectively, because the hedged forecasted transaction will not occur.

7. Long-term Debt

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

	December 31, 2008	December 31, 2007
	(in thousands)	
Senior notes	$ 357,500	$ 357,500
Revolving loans	768,729	124,000
Total	1,126,229	481,500
Less: current portion		
Long-term debt	$ 1,126,229	$ 481,500
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 500,000
Unfunded Lehman commitments	(8,646)	
Revolving loans	(768,729)	(124,000)
Letters of credit	(16,257)	(27,263)
Total available	$ 106,368	$ 348,737

Long-term debt maturities as of December 31, 2008 for each of the next five years are as follows.

Year Ending December 31,	Amount (in thousands)
2009	$
2010	
2011	768,729
2012	
2013	357,500
Thereafer	
Total	$ 1,126,229

In the year ending December 31, 2008, the Partnership borrowed $844,729,000 under its revolving credit facility; these borrowings were made primarily to fund capital expenditures. During the same period, the Partnership repaid $200,000,000 with proceeds from an equity offering. In the years ending December 31, 2007 and 2006, the Partnership borrowed $283,230,000 and $195,300,000 respectively; these funds were used primarily to finance capital expenditure projects and to temporary finance the TexStar acquisition. During the same period, the Partnership repaid $421,430,000 and $180,600,000 of these borrowings with proceeds from private equity offering and term loans.

Senior Notes. In 2006, the Partnership and Finance Corp. issued $550,000,000 senior notes that mature on December 15, 2013 in a private placement (senior notes). 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 its outstanding senior notes on or before December 15, 2009. Under the senior notes terms, no further redemptions are permitted until December 15, 2010. The Partnership made the redemption at a price of 108.375 percent of the principal amount plus accrued interest. Accordingly, a redemption premium of $16,122,000 was recorded as loss on debt refinancing and unamortized loan origination costs of $4,575,000 were written off and charged to loss on debt refinancing in the year ended December 31, 2007. A portion of the proceeds of an equity offering was used to redeem the senior notes. In

September 2007, the Partnership exchanged its then outstanding 8.375 percent senior notes which were not registered under the Securities Act of 1933 for senior notes with identical terms that have been so registered.

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,

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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.

The senior notes are guaranteed by each of the Partnership s current subsidiaries (the Guarantors) as of December 31, 2008, with the exception of WGP-KHC, LLC, the entity that owns the FrontStreet assets, and Finance Corp. These note guarantees are the joint and several obligations of the Guarantors. Guarantors may not sell or otherwise dispose of all or substantially all of its properties or assets if such sale would cause a default under the terms of the senior notes. Events of default include nonpayment of principal or interest when due; failure to make a change of control offer (explained below); failure to comply with reporting requirements according to SEC rules and regulations; and defaults on the payment of obligations under other mortgages or indentures. Since certain wholly-owned subsidiaries do not guarantee the senior notes, the condensed consolidating financial statements of the guarantors and non-guarantors as of and for the years end December 31, 2008 and 2007 are disclosed below in accordance with Rule 3-10 of Regulation S-X.

Condensed Consolidating Balance Sheets

December 31, 2008

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
ASSETS				
Total current assets	$ 212,712	$ 23,691	$	$ 236,403
Property, plant and equipment, net	1,612,387	91,167		1,703,554
Total other assets	518,682			518,682
TOTAL ASSETS	$ 2,343,781	$ 114,858	$	$ 2,458,639
LIABILITIES & PARTNERS CAPITAL				
Total current liabilities	$ 210,241	$ 6,709	$	$ 216,950
Long-term liabilities from risk management activities	560			560
Other long-term liabilities	15,487			15,487
Long-term debt	1,126,229			1,126,229
Minority interest	13,161			13,161
Partners capital	978,103	108,149		1,086,252
TOTAL LIABILITIES & PARTNERS CAPITAL	$ 2,343,781	$ 114,858	$	$ 2,458,639

December 31, 2007

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
ASSETS				
Total current assets	$ 170,415	$ 9,478	$	$ 179,893
Property, plant and equipment, net	818,054	95,055		913,109
Total other assets	185,408			185,408
TOTAL ASSETS	$ 1,173,877	$ 104,533	$	$ 1,278,410
LIABILITIES & PARTNERS CAPITAL				
Total current liabilities	$ 191,580	$ 6,678	$	$ 198,258

Long-term liabilities from risk management activities	15,073			15,073
Other long-term liabilities	15,393			15,393
Long-term debt	481,500			481,500
Minority interest			4,893	4,893
Partners capital	470,331	97,855	(4,893)	563,293
TOTAL LIABILITIES & PARTNERS CAPITAL	$ 1,173,877	$ 104,533	$	$ 1,278,410

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Condensed Consolidating Statements of Operations

For the Year Ended December 31, 2008

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,816,346	$ 47,458	$	$ 1,863,804
Total operating costs and expenses	1,659,810	40,021		1,699,831
OPERATING INCOME	156,536	7,437		163,973
Interest expense, net	(63,243)			(63,243)
Other income and deductions, net	446	(114)		332
INCOME BEFORE INCOME TAXES AND MINORITY INTEREST	93,739	7,323		101,062
Income tax benefit	(266)			(266)
Minority interest	312			312
NET INCOME	$ 93,693	$ 7,323	$	$ 101,016

For the Year Ended December 31, 2007

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,168,054	$ 22,184	$	$ 1,190,238
Total operating costs and expenses	1,114,843	16,031		1,130,874
OPERATING INCOME	53,211	6,153		59,364
Interest expense, net	(52,016)			(52,016)
Loss on debt refinancing	(21,200)			(21,200)
Other income and deductions, net	1,308	(56)		1,252
INCOME BEFORE INCOME TAXES AND MINORITY INTEREST	(18,697)	6,097		(12,600)
Income tax expense	931			931
Minority interest		305		305
NET INCOME (LOSS)	$ (19,628)	$ 5,792	$	$ (13,836)

Condensed Consolidating Statements of Cash Flow

For the Year Ended December 31, 2008

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by (used in) operating activities	$ 181,530	$ (232)	$	$ 181,298

Net cash flows used in investing activities	(935,848)	(12,781)		(948,629)
Net cash flows provided by financing activities	727,095	7,864		734,959

For the Year Ended December 31, 2007

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by operating activities	$ 74,413	$ 5,116	$	$ 79,529
Net cash flows used in investing activities	(151,451)	(6,482)		(157,933)
Net cash flows provided by financing activities	95,721	3,722		99,443

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The Partnership may redeem the 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. At any time before December 15, 2010, the Partnership may redeem some or all of the notes at a redemption price equal to 100 percent of the principal amount plus a make-whole premium, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date.

Upon a change of control, each holder of notes will be entitled to require us to purchase all or a portion of its notes at a purchase price equal to 101 percent of the principal amount thereof, plus accrued and unpaid interest and liquidated damages, if any, to the date of purchase. The Partnership s ability to purchase the notes upon a change of control will be limited by the terms of the Partnership s debt agreements, including the Credit Facility. Subsequent to the GE EFS Acquisition, no bond holder has exercised this option.

The senior notes contain covenants that, among other things, limit the Partnership s ability and the ability of certain of the Partnership s subsidiaries to: (i) incur additional indebtedness; (ii) pay distributions on, or repurchase or redeem equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into certain types of transactions with affiliates; and (vi) sell assets or 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 and its restricted subsidiaries will no longer be subject to many of the foregoing covenants.

Finance Corp. has no operations and will not have revenue other than as may be incidental co-issuer of the senior notes. Since the Partnership has no independent operations, the guarantees are full 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 for periods ending prior to December 31, 2007.

Fourth Amended and Restated Credit Agreement. At December 31, 2007, RGS Fourth Amended and Restated Credit Agreement (Credit Facility) allowed for borrowings of $600,000,000 in term loans and $500,000,000 in a revolving credit facility. The availability for letters of credit was increased to $100,000,000. RGS has the option to increase the commitments under the revolving credit facility or the term loan facility, or both, by an amount up to $250,000,000 in the aggregate, provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase in commitments have been met. On January 15, 2008, the revolving credit facility under the Credit Facility was expanded to $750,000,000 and on February 13, 2008, the revolving credit facility under the Credit Facility was expanded to $900,000,000. The Partnership 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. 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 of December 31, 2008, the Partnership borrowed all but $8,646,000 of the amount committed by Lehman under the Credit Facility. Lehman has declined requests to honor its remaining commitment, effectively reducing the total size of the Credit Facility s capacity to $891,354,000. Further, if the Partnership makes repayments of loans against the revolving facility which were, in part, funded by Lehman, the amounts funded by Lehman may not be reborrowed. Further information on the status of Lehman s commitment is described in Note 16, Subsequent Events.

The outstanding balance of revolving debt 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,

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commitment fees, and amortization of debt issuance costs were 6.27 percent, 8.78 percent and 7.70 percent for the years ended December 31, 2008, 2007, and 2006, respectively. The senior notes bear interest at a fixed rate of 8.375 percent.

RGS must pay (i) a commitment fee equal to 0.30 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 1.50 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 EBITDA and EBITDA to interest expense within certain threshold ratios. At December 31, 2008 and 2007, 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 Credit Facility also contains various covenants that limit (subject to certain exceptions and negotiated baskets), among other things, the ability of RGS (but not the Partnership):

- to incur indebtedness;
- to grant liens;
- enter into sale and leaseback transactions;
- to make certain investments, loans and advances;
- to dissolve or enter into a merger or consolidation;
- to enter into asset sales or make acquisitions;
- to enter into transactions with affiliates;
- to prepay other indebtedness or amend organizational documents or transaction documents (as defined in the Credit Facility);
- to issue capital stock or create subsidiaries; or
- to 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.

The Partnership treated the amendment of the Credit Facility as an extinguishment and reissuance of debt, and therefore recorded a charge to loss on debt refinancing of $5,626,000 in the year ended December 31, 2006.

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8. 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, 2007	$ 10,247	$ 66,676	$	$	$ 76,923
Additions		5,242			5,242
Disposals	(108)				(108)
Amortization	(771)	(3,482)			(4,253)
Balance at December 31, 2007	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

The weighted average remaining amortization periods for permits and licenses, contracts, trade names, and customer relations are 10.9, 17.6, 14.1 and 18.3 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)
2009	$ 12,453
2010	12,359
2011	11,101
2012	10,808
2013	10,808

Goodwill. Goodwill activity consists of the following.

	Gathering and Processing	Transportation	Contract Compression	Total
Balance at January 1, 2007	$ 23,309	$ 34,243	$	$ 57,552
Additions	36,523			36,523
Balance at December 31, 2007	59,832	34,243		94,075
Additions	3,401		164,882	168,283
Balance at December 31, 2008	$ 63,233	$ 34,243	$ 164,882	$ 262,358

9. Fair Value Measures

On January 1, 2008, the Partnership adopted the provisions of SFAS 157 for financial assets and liabilities. SFAS 157 became effective for financial assets and liabilities on January 1, 2008. On January 1, 2009, the Partnership will apply the provisions of SFAS 157 for non-recurring fair value measurements of non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. SFAS 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations.

SFAS 157 establishes 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 markets accessible by the Partnership;

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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.

SFAS 157 encourages entities to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership s financial assets and liabilities measured at fair value on a recurring basis are risk management assets and liabilities related to interest rate and commodity swaps. Risk management assets and liabilities 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. The Partnership has no financial assets and liabilities as of December 31, 2008 valued based on inputs classified as Level 3 in the hierarchy.

The estimated fair value of financial instruments was determined using available market information and valuation methodologies. 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. Risk management assets and liabilities are carried at fair value. Long-term debt other than the senior notes was comprised of borrowings under which, at December 31, 2008 and 2007, accrued interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value for the long term debt amounts outstanding. The estimated fair value of the senior notes based on third party market value quotations was $244,887,500 and $367,778,000 as of December 31, 2008 and 2007, respectively.

10. Leases

The Partnership leases office space and certain equipment for various periods and determined that these leases are operating leases. The following table is a schedule of future minimum lease payments for operating leases that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2008.

For the year ended December 31,	**Operating**	**Capital**
	(in thousands)	
2009	$ 2,357	$ 612
2010	2,526	593
2011	2,348	422
2012	1,926	448
2013	1,262	462
Thereafter	5,506	7,562
Total minimum lease payments	$ 15,925	10,099
Less: Amount representing estimated executory costs (such as maintenance and insurance), including profit thereon, included in minimum capital lease payments		1,972
Net minimum capital lease payments		8,127
Less: Amount representing interest		4,742
Present value of net minimum capital lease payments		$ 3,385

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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 balance sheet.

	December 31, 2008 (in thousands)
Gross amount included in gathering and transmission systems	$ 3,000
Gross amount included in other property and equipment	560
Less accumulated amortization	(421)
	$ 3,139
Current obligation under capital lease	$ 535
Noncurrent obligation under capital lease	2,850
	$ 3,385

Total rent expense for operating leases, including those leases with terms of less than one year, was $2,576,000, $1,597,000, and $1,721,000 for the years ended December 31, 2008, 2007, and 2006, respectively.

11. Commitments and Contingencies

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

Construction and Operating Agreement. Prior to the acquisition of FrontStreet by the Partnership, FrontStreet entered into a construction and operation agreement (C&O Agreement) contract with a third party. Under the terms of the C&O Agreement, the third party is responsible for operating, maintaining and repairing the FrontStreet gathering system. Subject to prior approval, the Partnership is responsible for paying for capital additions and expenses incurred by the operator of the FrontStreet gathering system. The C&O Agreement shall remain in effect until such time as the gathering agreement (discussed below) terminates or the third party is removed as operator in accordance with terms of the C&O Agreement.

The C&O Agreement also requires the third party to comply with all applicable environmental standards. While the Partnership would be responsible for any environmental contamination as a result of the operation of the FrontStreet gathering system, remedies are provided to the Partnership under the C&O Agreement allowing it to recover costs incurred to remediate a contaminated site. Additionally, the C&O Agreement states that the Partnership is specifically responsible for the removal, remediation, and abatement of Polychlorinated Biphenyls (Remediation Work). However, under the terms of the C&O Agreement, the Partnership can include up to $2,200,000 of expenditures for Remediation Work related to conditions in existence prior to October 1994. The Partnership has obtained an indemnification against any environmental losses for preexisting conditions prior to the acquisition date from the previous owner. The Partnership has escrowed $750,000 in the event the third party does not agree to include in the cost of service expenditures for Remediation Work. The C&O Agreement shall remain in effect until such time as the gathering agreement (discuss below) terminates or the third party is removed as operator in accordance with terms of the C&O Agreement. In 2008, the Partnership was reimbursed for all the remediation work done and pursuant to the C&O Agreement the escrow balance was released to the previous owners.

Gathering Agreement. Prior to the acquisition of FrontStreet by the Partnership, FrontStreet has entered into a gathering agreement (Gathering Agreement) contract into with a third party, whereby the third party dedicates for gathering by the FrontStreet gathering system all of the commercially producible gas in a defined list of producing fields. The Gathering Agreement allows the Partnership to charge a per unit gathering fee (the Gathering Fee) calculated on estimated cost of service over the total estimated units to be transported in a calendar year. The Gathering Fee is predetermined for a calendar year by November 7 of the preceding calendar year and then subject to redetermination on June 7. As part of the redetermination process, the Gathering Fee is

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trued-up, inclusive of interest, based on actual costs incurred including abandonment costs and actual units transported. The term of the Gathering Agreement is for as long as gas is capable of being produced in commercial quantities, subject to certain exceptions in the event of an ownership change of the gas field, or the removal of the third party as operator of the FrontStreet gathering system.

Annual Settlement Payment Agreement. The Partnership and the third party are also parties to an annual settlement payment agreement (ASPA) which provides the Partnership with a fixed return on its investment in the FrontStreet gathering system. The ASPA also provides the mechanism for recovery of the costs of current period Remediation Work. The amount due under the ASPA is calculated monthly, inclusive of interest. Payments under the ASPA for a calendar year are due on the following March 15. The term of the ASPA is the same as the Gathering Agreement.

Escrow Payable. At December 31, 2008, $1,510,000 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. In the El Paso PSA, El Paso indemnified the predecessor of our operating partnership, RGS, 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.

In January 2008, pursuant to authorization by the Board of Directors of the General Partner, the Partnership agreed to settle the El Paso environmental remediation. Under the settlement, El Paso will 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 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.

Nexus Escrow. At December 31, 2008, $8,521,000 is included in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustments related to the Nexus Acquisition.

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.

TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning one of the Partnership s processing plants located in McMullen County, Texas (the Plant). The NOE alleges that, between March 9, 2006, and May 8, 2007, the 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. On April 3, 2008, TCEQ presented the Partnership with a written offer to settle the allegation in the NOE in exchange for payment of an administrative penalty of $480,000, and it later reduced its settlement demand to $360,000 in July 2008. The Partnership was unable to settle this matter on a satisfactory basis and the TCEQ has referred the matter to its litigation division for further administrative proceedings.

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Contingent Purchase of Sonat Assets. In March of 2008, the Partnership, through the Nexus Acquisition, obtained the rights to a contingent commitment to purchase 136 miles of pipeline that could facilitate the Nexus system integration into the Partnership s north Louisiana asset base. The purchase commitment is contingent upon the FERC declaring that the pipeline is no longer subject to its jurisdiction, together with approval of the current owner s abandonment and other customary closing conditions. In the event that all contingencies are satisfactorily resolved, the Partnership will pay Sonat $27,500,000. Furthermore, if the closing occurs on or prior to March 1, 2010, the Partnership will pay an additional $25,000,000 to the sellers, subject to certain terms and conditions.

On April 3, 2008, Sonat filed an application with the FERC seeking authorization to abandon by sale to Nexus 136 miles of pipeline and related facilities. The application also requested a determination that the facilities being sold to Nexus be considered non-jurisdictional, with certain facilities being gathering and certain facilities being intrastate transmission. Four producers submitted letters in support of the application and several Sonat shippers protested the application. The matter is currently pending.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC (Keyes) filed suit against Regency Gas Services LP, the Partnership, and the General Partner. Keyes entered into an output contract with the Partnership s predecessor in 1996 under which it purchased all of the helium produced at the Lakin processing plant in southwest Kansas. 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 of which the Partnership no longer delivered any helium to Keyes. As a result, Keyes alleges it is entitled to an unspecified amount of damages for the costs of covering its purchases of helium. The Partnership filed an answer to this lawsuit and plans to defend itself vigorously.

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. If the Kansas Department of Revenue determines that the condensate sales are taxable, then the Partnership may be subject to additional taxes for past and future condensate sales.

Purchase Commitments. At December 31, 2008, the Partnership has purchase obligations totaling approximately $323,341,000, of which $104,852,000 relate to the purchase of major compression components unrelated to the Haynesville Expansion Project, that extend until the year ending December 31, 2010 and $218,489,000 of commitments related to the Haynesville Expansion Project that extend until the year ending December 31, 2009. Some of these commitments have cancellation provisions. See Note 16, Subsequent Events, for more information regarding the operating lease facility that we may use to finance the acquisition of compression equipment in 2009.

12. Related Party Transactions

Concurrent with the closing of the Partnership s IPO, the Partnership paid $9,000,000 to an affiliate of HM Capital Partners to terminate a management services contract with a remaining term of nine years. TexStar paid $361,000 to HM Capital Partners for the year ended December 31, 2006 in relation to a management services contract. In connection with the TexStar Acquisition, the Partnership paid $3,542,000 to terminate TexStar s management services contract.

BBOG is a natural gas producer on the Partnership s gas gathering and processing system. At the time of the TexStar Acquisition, BBOG entered into an agreement providing for the long term dedication of the production from its leases to the Partnership. In July 2007, BBOG sold its interest in the largest of these leases to an unrelated third party. BBE is the lessee of office space in the south Texas region where the Partnership subleased offices for which it paid $151,000 and $70,000 in the years ended December 31, 2007 and 2006, respectively.

Concurrent with the TexStar Acquisition, a $600,000 promissory note was repaid in full. TexStar paid a transaction fee in the amount of $1,200,000 to an affiliate of HM Capital Partners upon completing its acquisition of the Como Assets. This amount was capitalized as a part of the purchase price.

In conjunction with distributions by the Partnership for limited and general partner interests, HM Capital Partners and affiliates received cash distributions of $10,308,000, $24,392,000, and $20,139,000 during the years ended December 31, 2008, 2007, and 2006, respectively, as a result of their ownership interests in the Partnership.

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.

Under an omnibus agreement, Regency Acquisition LP, the entity that formerly owned the General Partner, agreed to indemnify the Partnership in an aggregate not to exceed $8,600,000, generally for three years after February 3, 2006, for certain environmental noncompliance and remediation liabilities associated with the assets transferred to the Partnership and occurring or existing before that date. To date, no claims have been made against the omnibus agreement. On February 3, 2009, the omnibus agreement expired, with no claims having been filed.

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, our General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $26,899,000, $27,628,000, and $16,789,000 were recorded in the Partnership s financial statements during the years ended December 31, 2008, 2007, and 2006, 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. In the year ending December 31, 2008, three senior management members resigned from their positions, thus effectively reducing management interest in the General Partner to 3.8 percent.

GE EFS and certain members of the Partnership s management made a capital contribution aggregating to $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, 2008 and 2007, respectively.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS and affiliates received cash distributions of $35,054,000 and $14,592,000 during the year ended December 31, 2008 and 2007, respectively, as result of their ownership interests in the Partnership.

In conjunction with distributions by the Partnership to its limited and general partner interests, certain members of management received cash distributions of $1,887,000 in the year ended December 31, 2008 as a result of their ownership interests in the Partnership.

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.

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The Partnership s contract compression segment provides contract compression services to CDM MAX LLC, a related party. The Partnership s related party receivables and payables as of December 31, 2008 relate to CDM MAX LLC.

13. Concentration Risk

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

			Year Ended	
	Reportable Segment	December 31, 2008	December 31, 2007	December 31, 2006
			(in thousands)	
Customer				
Customer A	Transportation	*	*	$ 89,736
Supplier				
Supplier A	Transportation	$ 75,464	$ 157,046	*
Supplier A	Gathering and Processing	243,075	*	*
Supplier B	Gathering and Processing	*	*	67,751

* Amounts are less than 10 percent of the total revenues 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.

14. Segment Information

The Partnership has three reportable segments: i) gathering and processing, ii) transportation and iii) contract compression. Gathering and processing involves the collection of hydrocarbons from producer wells across the five operating regions and transportation of them to a plant 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. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment.

The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with larger pipelines or trading hubs and other markets. The Partnership performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenues are primarily fee based and involve minimal direct exposure to commodity price fluctuations. The Partnership also purchases natural gas at the inlets to the pipeline and sells this gas at its outlets.

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 our compression units, which are modified as necessary to adapt to customers changing operating conditions.

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 is defined

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as total revenues, including service fees, less cost of gas and liquids. Management believes segment margin is an important measure because it is directly related to volumes and commodity price changes. Operation and maintenance expenses are 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 operation and maintenance expenses. These expenses are largely independent of the volume throughput but fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

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

	Gathering and Processing	Transportation	Contract Compression	Corporate	Eliminations	Total
			(in thousands)			
External Revenue						
Year ending December 31, 2008	$ 1,205,781	$ 525,474	$ 132,549	$	$	$ 1,863,804
Year ending December 31, 2007	812,861	377,377				1,190,238
Year ending December 31, 2006	645,770	251,095				896,865
Intersegment Revenue						
Year ending December 31, 2008		198,294	4,573		(202,867)	
Year ending December 31, 2007		101,734			(101,734)	
Year ending December 31, 2006		39,504			(39,504)	
Cost of Sales						
Year ending December 31, 2008	949,401	447,313	11,619			1,408,333
Year ending December 31, 2007	658,100	318,045				976,145
Year ending December 31, 2006	534,398	206,048				740,446
Segment Margin						
Year ending December 31, 2008	256,380	78,161	125,503		(4,573)	455,471
Year ending December 31, 2007	154,761	59,332				214,093
Year ending December 31, 2006	111,372	45,047				156,419
Operation and Maintenance						
Year ending December 31, 2008	82,689	3,614	49,799		(4,473)	131,629
Year ending December 31, 2007	53,496	4,504				58,000
Year ending December 31, 2006	35,008	4,488				39,496
Depreciation and Amortization						
Year ending December 31, 2008	58,900	14,215	28,448	1,003		102,566
Year ending December 31, 2007	40,309	13,545		1,220		55,074
Year ending December 31, 2006	26,831	11,927		896		39,654
Assets						
December 31, 2008	1,054,166	374,659	881,552	148,262		2,458,639
December 31, 2007	886,477	329,862		62,071		1,278,410
Goodwill						
December 31, 2008	63,233	34,243	164,882			262,358
December 31, 2007	59,832	34,243				94,075
Expenditures for Long-Lived Assets						
Year ending December 31, 2008	124,736	59,303	186,063	4,981		375,083
Year ending December 31, 2007	112,813	16,555		416		129,784
Year ending December 31, 2006	192,115	29,810		1,725		223,650

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

	December 31, 2008	Year Ended December 31, 2007 (in thousands)	December 31, 2006
Net income (loss) from continuing operations	$ 101,016	$ (13,836)	$ (7,244)
Add (deduct):			
Operation and maintenance	131,629	58,000	39,496
General and administrative	51,323	39,713	22,826
Loss on asset sales	472	1,522	
Management services termination fee	3,888		12,542
Transaction expenses	1,620	420	2,041
Depreciation and amortization	102,566	55,074	39,654
Interest expense, net	63,243	52,016	37,182
Loss on debt refinancing		21,200	10,761
Other income and deductions, net	(332)	(1,252)	(839)
Income tax expense	(266)	931	
Minority interest in net income from subsidiary	312	305	
Total segment margin	$ 455,471	$ 214,093	$ 156,419

15. Equity-Based Compensation

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 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 $4,318,000, $15,534,000, and $2,906,000 is recorded in general and administrative in the statement of operations for the years ended December 31, 2008, 2007, and 2006, 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 common units on a net basis. During the year ended December 31, 2008, two former executives of the Partnership exercised 135,000 unit options. Since there were no options granted during the year ended December 31, 2008, the following assumptions apply to the options granted during the years ended December 31, 2007 and 2006.

	Year Ended December 31, 2007	December 31, 2006
Weighted average expected life (years)	4	4
Weighted average expected dividend per unit	$ 1.51	$ 1.40
Weighted average grant date fair value of options	$ 2.31	$ 1.32
Weighted average risk free rate	4.60%	4.25%
Weighted average expected volatility	16.0%	15.0%
Weighted average expected forfeiture rate	11.0%	5.0%

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The common unit options activity for the years ending December 31, 2008, 2007, and 2006 is as follows.

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

2006

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *(in thousands)
Outstanding at the beginning of period		$		
Granted	943,900	21.05		
Exercised				
Forfeited or expired	(34,300)	21.75		
Outstanding at end of period	909,600	21.06	9.3	$ 5,522
Exercisable at the end of the period				

* 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.

The Partnership will make distributions to non-vested restricted common units at the same rate 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 $14,856,000 of compensation expense related to the grants under LTIP primarily over the next three years.

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The restricted (non-vested) common unit activity for the years ending December 31, 2008, 2007, and 2006 is as follows.

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

2006

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period		$
Granted	516,500	21.06
Vested		
Forfeited or expired		
Outstanding at the end of period	516,500	21.06

16. Subsequent Events

Partner Distributions. On January 27, 2009, the Partnership declared a distribution of $0.445 per common and subordinated unit including units equivalent to the General Partner s two percent interest in the Partnership, and an aggregate distribution of $577,000 with respect to incentive distribution rights, payable on February 13, 2009 to unitholders of record at the close of business on February 6, 2009.

On February 9, 2009 and February 17, 2009, 7,276,506 Class D and 19,103,896 subordinated units, respectively, converted into common units on a one for one basis.

Joint Venture Formation. The Partnership, GECC and the Alinda Investors entered into a definitive agreement to form a joint venture to finance and construct our previously announced Haynesville Expansion Project. The project will transport gas from the Haynesville Shale. In connection with the joint venture, the Partnership will contribute all of its ownership interests in RIGS, with an estimated fair value of $400,000,000, in exchange for a 38 percent general partnership interest in the joint venture and a cash payment equal to the total Haynesville Expansion Project capital expenditures paid through the closing date, subject to certain adjustments. GECC and the Alinda Investors have agreed to contribute $126,500,000 and $526,500,000 in cash, respectively, in return for a 12 percent and a 50 percent general partnership interest in the joint venture, respectively.

The Partnership will serve as the operator of the joint venture, and will provide all employees and services for the operation and management of the joint venture s assets. The Partnership expects to close the joint venture transaction as promptly as practicable following the satisfaction of the closing conditions, but no later than April 30, 2009.

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Credit Agreement Amendment. On February 26, 2009, RGS entered into Amendment Agreement No. 7 (the Amendment) with Wachovia Bank, National Association, as administrative agent, and the lenders party thereto in order to amend the Credit Agreement. The Amendment will become effective upon the closing of the Contribution Agreement and the satisfaction of certain other conditions precedent.

Upon its effectiveness, the Amendment, among other things, (a) authorizes the contribution by Regency HIG of its ownership interests in RIGS to the joint venture and future investments in the joint venture of up to $135,000,000 in the aggregate, (b) permits distributions by RGS to the Partnership in an amount equal to the outstanding loans, interest and fees under a $45,000,000 revolving credit facility with GECC entered into on February 26, 2009, (c) adds an additional financial covenant that limits the ratio of senior secured indebtedness to EBITDA, (d) provides for certain EBITDA adjustments in connection with the Haynesville Expansion Project, and (e) increases the applicable margins and commitment fees applicable to the credit facility, as further described below.

Upon the effectiveness of the Amendment, (a) 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 LIBOR rate for a borrowing with a one-month interest period plus 1.50 percent, (b) the applicable margin that is used in calculating interest shall range from 1.50 percent to 2.25 percent for base rate loans and from 2.50 percent to 3.25 percent for Eurodollar loans, and (c) commitment fees will range from 0.375 percent to 0.500 percent.

The Amendment prohibits RGS or its subsidiaries from allowing the joint venture to incur or permit to exist any preferred interests or indebtedness for borrowed money of the joint venture prior to the completion date of the Haynesville Expansion Project. RGS and GECC executed a side letter on February 26, 2009 confirming that, after the closing of the Contribution Agreement, they will not permit their representatives on the management committee of the joint venture to violate such restriction.

Revolving Credit Facility. On February 26, 2009, the Partnership entered into a $45,000,000 unsecured revolving credit agreement with GECC, as administrative agent, the lenders party thereto and the guarantors party thereto (the Revolving Credit Facility). The proceeds of the Revolving Credit Facility may be used for expenditures made in connection with the Haynesville Expansion Project prior to the earlier to occur of the effectiveness of the Amendment and April 30, 2009. The commitments under the Revolving Credit Facility will terminate automatically on the earlier to occur of the effectiveness of the Amendment and April 30, 2009, and the Partnership will be required to prepay all outstanding loans upon the effectiveness of the Amendment. The maturity date under the Revolving Credit Facility will be the earlier of the date that is three months after the final maturity date under the Credit Agreement and November 15, 2011.

Interest will be calculated, at our option, at either (a) the greater of (i) a federal funds effective rate plus 0.50 percent plus the applicable margin or (ii) an adjusted LIBOR rate for a borrowing with a one-month interest period plus 1.50 percent plus the applicable margin and (b) an adjusted LIBOR rate plus the applicable margin. The applicable margin that is used in calculating interest shall range from 3.00 percent to 10.00 percent for base rate loans and from 4.00 percent to 11.00 percent for Eurodollar loans. The Partnership shall pay a 6 percent closing fee. The Partnership shall pay a commitment fee of 0.75 percent per annum on the unused portion of the commitments under the Revolving Credit Facility.

The Partnership is required to comply with the covenants set forth in the Credit Agreement and in the Partnership s Indenture dated as of December 12, 2006 among us, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee. The Revolving Credit Facility is guaranteed by our subsidiaries (as defined in the Revolving Credit Facility) (other than RIGS, unless the Amendment does not become effective by April 30, 2009).

Lehman Commitments on Revolving Credit Agreement. As of February 20, 2009, the amount of unfunded Lehman commitments has been reduced to $5,578,000 due to other banks in the syndicate increasing their commitments.

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Operating Lease Facility. On February 26, 2009, CDM entered into an operating lease facility with Caterpillar Financial Services Corporation whereby CDM has the ability to lease compression equipment with an aggregate value of up to $75,000,000. CDM paid commitment and arrangement fees of $375,000. As part of the facility, CDM will pay 150 bps on the value of the equipment funded for each lease as funded. The facility is available for leases with inception dates up to and including December 31, 2009, and mitigates the need to use available capacity under the existing Credit Facility. Each compressor acquired under this facility shall have a lease term of one hundred twenty (120) months with a fair value buyout option at the end of the lease term. At the end of the lease term, CDM shall also have an option to extend the lease term for an additional period of sixty (60) months at an adjusted rate equal to the fair market rate at that time. In the event CDM elects not to exercise the buyout option, the equipment must be returned in a manner fit for use at the end of the lease term. In addition to the fair value buyout option at the end of the lease term, early buyout option provisions exist at month sixty (60) and at month eighty four (84) of the one hundred twenty (120) month lease term. Covenants under the lease facility require CDM to maintain certain fleet utilization levels as of the end of each calendar quarter as well as a total debt to EBITDAR (Earnings Before Interest, Taxes, Depreciation, Amortization, and Rental expense) ratio of less than or equal to 4:1. In addition, covenants restrict the concentration of revenues derived from the equipment acquired under the lease facility. The terms of the lease facility do not include contingent rentals or escalation clauses.

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17. Quarterly Financial Data (Unaudited)

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)	Basic Earnings per Common and Subordinated Unit	Diluted Earnings per Common and Subordinated Unit	Basic and Diluted Earnings per Class B Common Unit	Basic and Diluted Earnings per Class C Common Unit	Basic and Diluted Earnings per Class D Common Unit	Basic and Diluted Earnings per Class E Common Unit
	(in thousands except earnings per unit)								
2008									
March 31[1]	$ 405,235	$ 25,877	$ 10,348	$ 0.14	$ 0.13	$	$	$ 0.21	$
June 30	546,705	26,512	9,972	0.12	0.12			0.26	
September 30	547,175	64,956	48,907	0.56	0.53			0.26	
December 31	364,689	46,628	31,789	0.39	0.38			0.26	
2007[2]									
March 31	$ 256,428	$ 13,480	$ (1,295)	$ (0.06)	$ (0.06)	$	$ 0.48	$	$
June 30	302,828	8,768	(7,263)	(0.16)	(0.16)				0.07
September 30	295,825	21,545	(9,833)	(0.23)	(0.23)				0.63
December 31	335,157	15,571	4,555	0.03	0.03				0.53

(1) The operating income amount disclosed above differs immaterially from the amount disclosed in the Form 10-Q.

(2) The quarterly amounts have been recast for the FrontStreet acquisition which was accounted for as an as-if pooling transaction.

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